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THE COST OF TRADE DISTORTION: BRITAIN'S CARBON PRICE SUPPORT AND CROSS-BORDER ELECTRICITY TRADE

This Working Paper has replaced CWPE1951

Bowei Guo

David Newbery

10 March 2020

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EPRG WORKING PAPER

The Cost of Trade Distortion: Britain's Carbon Price Support and Cross-border Electricity Trade[1]

Bowei Guo[a,b] and David Newbery[a]

EPRG Working Paper 2005

Cambridge Working Paper in Economics 2014

Abstract

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Keywords Carbon tax; Bilateral Trading; Electricity Market; Cost-benefit analysis

JEL Classification Q48; F14; D61; C13

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Publication March 2020

Financial Support InnovateUK and the UK Engineering and Physical Sciences Research Council (EPSRC) via the 'Prospering from the Energy Revolution" Industrial Strategy Challenge Fund', for the project "The value of Interconnection in a Changing EU Electricity system" (ICE) (EP/R021333/1).

[1] This replaces an earlier version of EPRG WP 1918, which seriously under-estimated the deadweight loss.

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Bowei Guo† David Newbery‡

March 10, 2020

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1 Introduction

Unilateral carbon pricing by one country or region is likely to distort trade and give rise to carbon leakage (Fowlie et al., 2016). Regional schemes like the European Union's (EU) Emission Trading Scheme (ETS) partially mitigate this by agreeing a uniform carbon price for some industries (the covered sector responsible for about half the total EU's emissions). While this should reduce the distortions within the EU, it is still prone to leakage to the rest of the world. The main industries affected by carbon leakage are carbon-intensive traded goods such as steel, aluminium and cement. Fowlie et al. (2016) choose US cement for a case study as it has experienced up to 20% import penetration, and is also highly concentrated. The electricity sector is, however, considerably more carbon intensive. In the EU-28, electricity accounts for just over 20% of total greenhouse gas (GHG) emissions, with very little decrease since 1990, while Figure 1 shows considerable fluctuations for the UK, remaining higher than the EU until the recent sharp decrease as coal has been driven out of the system by increases in carbon prices.

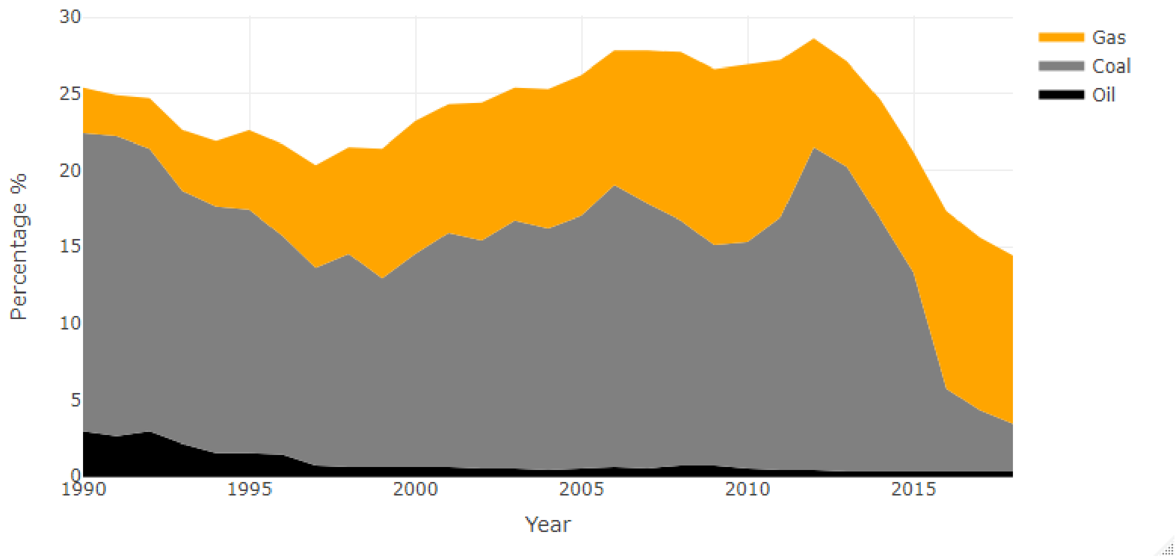


Figure 1: UK CO_{2e} emission from electricity sector as a share of total emissions, 1990-2018

The electricity sector is therefore of central importance when studying the impact of differential carbon prices. It has the added advantage that electricity is not widely traded outside the boundary of the EU, but within the EU, Great Britain (GB) faces potentially a 13% import share (and an actual share of 6.4% in 2018). A study of differential carbon prices within EU's Integrated Electricity Market[1] therefore isolates the impact, and allows us to ignore the rest of the world, except for the impact on global emissions.[2]

This paper develops a methodology for quantifying the impact of an asymmetric carbon tax on electricity trade within a closed region such as the EU or North America. The EU's *Third*

[1]The EU's Integrated Electricity Market opens national wholesale and retail electricity markets to trade and competition across the EU.

[2]Electricity prices will feed through to other exporting industries and will give rise to some additional leakage, but this will be ignored in the present paper.

Electricity Package came into force in 2014, requiring market coupling of interconnectors. Before market coupling, traders had to buy interconnector volume and direction before knowing the market clearing price at each end, often resulting in inefficient trades. Market coupling ensured that interconnector capacity would be cleared at the same time as electricity markets, securing efficient trade. If market prices can be equilibrated without violating interconnector capacity constraints, prices at each end will be the same. Otherwise, trade will be set at full capacity and prices will diverge. Figure 4 shows the effect of coupling on the relationship between cross-border electricity trading and day-ahead price differences (of the two connected markets).

GB, The Netherlands and France have all been coupled since early 2014, while the interconnector between GB and the Single Electricity Market of the island of Ireland (comprising Northern Ireland, part of the UK, and the Republic of Ireland) was only coupled in October 2018. The interconnector linking GB to Belgium was not commissioned until 2019. We therefore restrict our study to GB's trade with France and The Netherlands from early 2014 to late 2018, before these other linkages became coupled.

In 2011, the UK Government decided to enact a gradually escalating Carbon Price Floor for fossil generation fuels to make low-carbon generation investment commercially viable. This came into effect in April 2013 and took the form of a carbon tax (the Carbon Price Support, CPS, an addition to the EU carbon price, see Figure 2) on generation fuels in GB (but not Northern Ireland). This paper quantifies the costs and benefits of cross-border electricity trading between interconnected countries in the presence of asymmetric distortionary carbon taxes. It takes GB as a case study and quantifies the impact of the CPS on electricity prices, interconnector flows, congestion income (from buying low and selling high), and social value from trade. It also estimates the deadweight loss and carbon leakage in the electricity sector created by the asymmetric carbon taxes. This has implications for the design and ideally harmonisation of the EU carbon tax to improve the efficiency of electricity trade.

We estimate that over 2015-2018 when the CPS stabilised at £18 (€20) /tCO_2, the CPS raised the GB day-ahead price by an average of €11.43/MWh (about 28% of the GB wholesale price) after allowing for replacement by cheaper imports. The CPS increased GB imports by 12.4 TWh/yr (about 4% of the GB annual electricity demand), thereby reducing carbon tax revenue by €101 m/yr (about 10% of the 2017 CPS tax receipts). The commercial value of interconnectors (measured by congestion income) increased by €153 m/yr (by 80% relative to the zero CPS case), half of which was transferred to foreign interconnector owners. The sum of the congestion income and the importer and exporter surplus is the social value of interconnector at €250 m/yr, but the asymmetric carbon taxes created deadweight losses of €80 m/yr, about 4% of the global emissions reduction benefit of the CPS of €2 bn/yr. Increased French exports raised French wholesale prices by 3.5% and Dutch wholesale prices by 2.8%. Finally, about 1.3% of the CO_2 emission reduction is undone by France (-0.4% by the Netherlands), and the monetary loss of this carbon leakage is about €27 m/yr (€-9 m/yr for The Netherlands), in total €18 m/yr.

1.1 Literature review

Previous literature has mostly focused on the impact of unilateral carbon taxes on the macro-level bilateral trade and carbon leakage under the 1997 Kyoto Protocol. Elliott et al. (2010) use a computable general equilibrium model to predict that countries uncommitted to the protocol will undo 20% of the reduction made by the committed countries, and adding full border tax adjustments would eliminate the leakage. Babiker (2005) uses a similar model to predict that the leakage rate can be as high as 130%, resulting in higher global emissions. Aichele and Felbermayr (2015) conduct an empirical *ex-post* evaluation of the protocol and find that the committed countries have increased 8% of its carbon imports, and the emission intensity of their imports has increased by 3%. Harstad (2012) argues that the solution to the market distortion is to allow countries to trade their emission allowance.

Folie et al. (2016) look at the domestic distortions arising from the oligopolistic nature of the cement market, where at high carbon taxes domestic market power is increased. Leakage makes matters worse, and both effects can be counteracted by suitable policies, including a Border Tax Adjustments (BTA), an export credit of the kind contemplated by the proposed European Commission's "Climate Law" (EC, 2019, p5). Metcalf (2008), in designing a politically acceptable carbon tax for the US, proposes a BTA to offset trade distortions, and an earned income tax credit designed to be distributionally neutral. Bovenberg and Goulder (1996) look at environmental tax distortions in a closed economy, finding that a full corrective environmental tax (that fully internalises the externality) would create additional distortions if there are other distorting revenue-raising taxes, arguing for a lower than Pigouvian tax on such externalities. As the GB carbon tax does not carry any BTA it can be expected to have distortionary impacts on trade, while its interactions with the rest of the tax system will be ignored here (as demand for electricity is assumed inelastic in the short run).

Studies of carbon taxes and electricity markets have so far focused on their price impact (e.g. Wild et al., 2015; Fabra and Reguant, 2014; Freitas and Da Silva, 2013; Jouvet and Solier, 2013; Kirat and Ahamada, 2011; Fell, 2010; Sijm et al., 2006; Guo and Castagneto Gissey, 2019), on the fuel mix and greenhouse gas emissions (e.g. Di Cosmo and Hyland, 2013; Chyong et al., 2019; Staffell, 2017), and on investment decisions within the power sector (e.g. Richstein et al., 2014; Green, 2018; Fan et al., 2010). Fabra and Reguant (2014) is perhaps the most useful for this paper in that they employ a rich micro-level data set to establish that emissions taxes are almost completely passed through to electricity prices, confirming the macro-econometric estimates of Chyong et al. (2020).

To the best of our knowledge, there is no *ex-post* econometric estimation of the effect of a carbon tax on cross-border electricity trade after market coupling, nor of the deadweight loss involved when applying carbon taxes asymmetrically across two electricity markets.

2 The British Carbon Price Floor and Market Coupling

This section introduces the British Carbon Price Floor (CPF) and market coupling that are the foundations of our empirical analysis. The CPF distorted cross-border electricity trade, while market coupling ensures that the high-price country always imports, facilitating our analysis for the counterfactual results where the CPF is not applied.

2.1 The British Carbon Price Floor

We are interested in the asymmetry in carbon prices between GB and Continental countries to which it is electrically interconnected. All these countries, together with GB until the end of 2020, were members of the EU Emissions Trading System (ETS) and as such faced a common carbon price. The EU ETS is a "cap and trade" model, with the cap set to limit the total CO_2 emissions from the covered sector within the EU. The 2008 financial crisis and increased renewables targets reduced demand for allowances (EUAs), causing prices to fall, reaching their lowest level in 2011. In response and as part of the evolving *Electricity Market Reform,* the UK Government announced plans for a Carbon Price Floor (CPF) to come into effect in April 2013, intended to make up for the failure of the EU ETS to give adequate, credible and sufficiently durable carbon price signals. The CPF was implemented by publishing a GB[3] Carbon Price Support (CPS) added to the EUA price to increase it to the projected CPF. The CPS grew from £4.94/tCO_2 in 2013 to £9.55/tCO_2 in 2014, and has been stabilised since 2015 at £18/tCO_2.

Consequently, the total GB carbon cost rose from £5/tCO_2 in early 2013 to nearly £40/tCO_2 by the end of 2018. Figure 2 shows the evolution of the (nominal) GB and the EU carbon prices. The two curves start diverging in 2013, with the gap becoming wider in 2014 and 2015. The dashed line represents the GB carbon cost target when the CPF was announced. It was not until late 2018 that the GB carbon cost finally met the initial trajectory, thanks to the reform of the EU ETS, which introduced a *Market Stability Reserve* that removes excess EUAs and increases its price (Newbery et al., 2019).

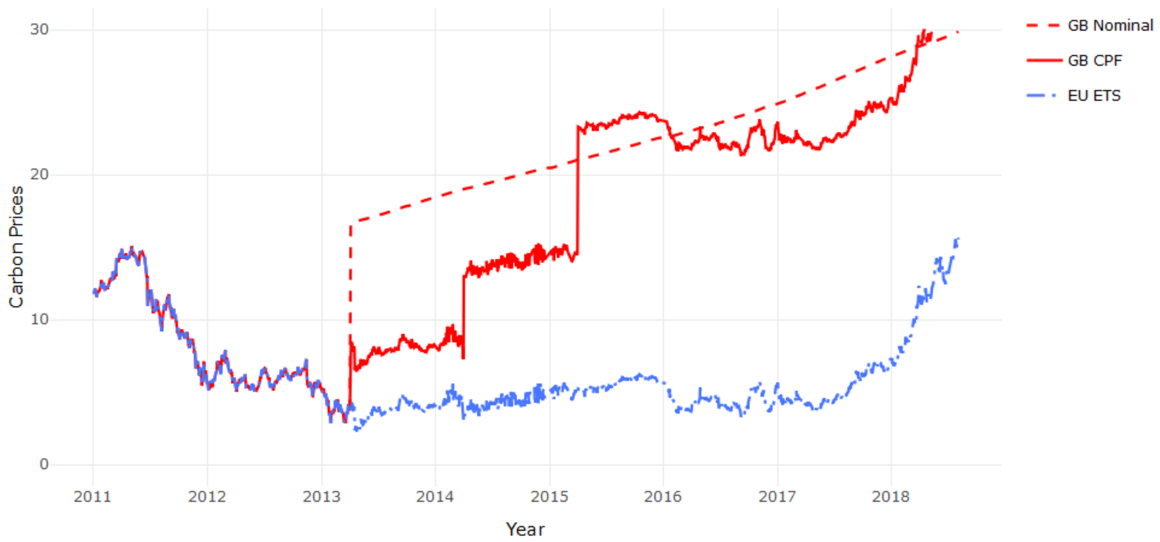
The CPS raises the cost of fossil-fuelled electricity generation. Figure 3 plots the 28-day moving average of the day-ahead prices for GB, France, and The Netherlands, as well as the price differences between the two connected markets. It also shows the variable cost (i.e. the short-run marginal cost) for Combined Cycle Gas Turbines (CCGTs) with 54.5%[4] thermal efficiency with EUA prices included (CPS excluded) as a measure of Continental gas generation costs.

In general, while GB prices are typically higher than Dutch prices, the CPS widens the price differences between the two markets. French prices are much more volatile than the others mainly because nearly 80%[5] of its gross electricity generation comes from nuclear power stations (in 2015), making its electricity system less flexible and resulting in more volatile prices. Another reason for the high volatility is that French prices are very weather-sensitive given their high domestic electrical heating load. During Q3-Q4 2016 and Q4 2017, France experienced major nuclear outages, which explains the much higher French prices during those periods. The variable cost for CCGTs partially explains the patterns of prices for the three

[3]Northern Ireland, which is part of the Single Electricity Market of the island of Ireland, is exempt to preserve an equal carbon price on the island.

[4]Measured at Lower Heating Value (LHV).

[5]From Eurostat at: https://ec.europa.eu/energy/en/news/get-latest-energy-data-all-eu-countries.



Source: Chyong, Guo and Newbery (2020).

Figure 2: Evolution of the European and GB carbon prices in power sector, £/tCO_2

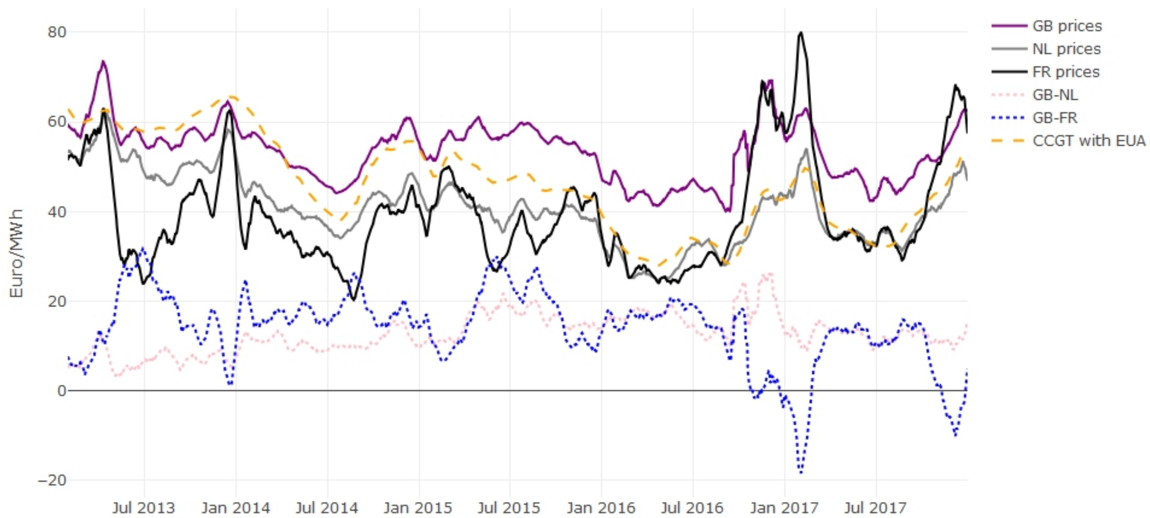


Figure 3: 28-day lagged moving average day-ahead prices, 2013-2017

markets, and best fits the dynamics of the Dutch price, where gas is the marginal fuel most of the time.

2.2 Market Coupling

The day-ahead electricity markets in Great Britain (GB), France, and The Netherlands were coupled from 4 February 2014. Following market coupling, bids to buy and offers to sell are fed into a European-wide auction. Each market operator solves for its own area price at which the area's supply and demand equate. When different market prices across the interconnector occur, cross-border electricity trade takes price, and either prices across the interconnector can be equalised without violaring capacity constraints, or, if not, the capacity is fully used and prices remain divergent.

(a) Pre-coupling, 2013 (b) Post-coupling, 2017

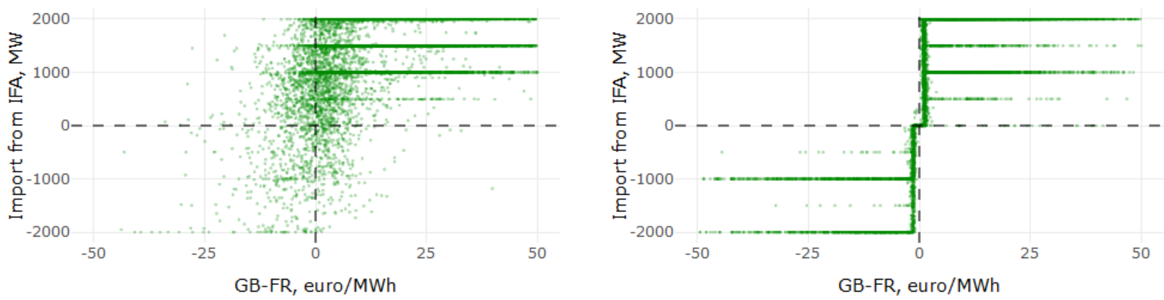


Figure 4: Day-ahead flows *v.s.* price differences between GB and France, 2013 and 2017

Figure 4 plots the relationship day-ahead flow (exports shown as negative) and price differences between GB and France for the entire year of 2013 and 2017, before and after the market coupling. The two countries are connected by four cables of 500 MW each for a total of 2 GW, hence the horizontal bands of observations at multiples of 500 MW are due to one or more cables under maintenance or network limitations. In 2013, before the market coupling (Figure 4a), capacity was inefficiently used with many inefficient power exchanges (dots in the second and fourth quadrants), while after the market coupling (Figure 4b) available capacity was efficiently used with no inefficiency.[6]

3 Theoretical Foundation

Consider two EU countries H (Home country, GB) and F (Foreign country) connected via an interconnector with capacity K. Without the CPS (but with the EUA price), wholesale electricity prices in each country are initially p_0^i, $i = \{H, F\}$ (subscript $j = 0$ indicates without the CPS, and 1 with). The net import to H over the interconnector is m_j ($-K \leq m_j \leq K$). Applying the CPS ($\tau > 0$) in H raises its wholesale price by Δp^H. The higher price in H induces more net imports ($\Delta m \geq 0$), which further changes generation in each country, with impacts on marginal costs in H and F and in turn wholesale prices. Our first aim is to estimate Δp^H, Δm and p_0^i, $i = \{H, F\}$,[7] with the estimate on Δp^H further informing us about the CPS

[6] The day-ahead flow that allocates capacity to the day-ahead market can differ from the final recorded cross-border physical flows because of intraday and balancing trades, although these are typically less than 5% of the total, so we focus on the day-ahead market as the only fully coupled market so far. The day-ahead prices are representative of the wholesale electricity price.

[7] p_1^i, $i = \{H, F\}$ are observed. Note $p_0^H + \Delta p^H \geq p_1^H$, because Δp^H measures the effect of the CPS on H's wholesale price with the net import fixed at m_0, while p_1^H is H's wholesale price after considering the change in net import Δm.

pass-through rate to H's wholesale prices.

As demand is assumed inelastic and as changes in prices and imports have no obvious impact in that hour's intermittent renewable [8] and nuclear power generation, residual demand (total demand minus renewable and nuclear generation) does not change with the carbon price. Therefore, increased net imports imply the same reduction (increase) in fossil generation in H (F).[9] These supply changes, given the asymmetry in carbon taxes, will have first order welfare effects. Our second aim to measure this welfare loss.

The changes in trading patterns potentially influence emissions in H and F, with implications for global emissions and welfare. The third aim is to estimate the carbon leakage of the CPS via interconnectors, as well as the total CO_2 emission reduction and its associated monetary value (in a world in which individual country changes lead to global changes).[10]

This section builds the theoretical foundation of our later empirical analysis. Our analysis is conducted hour by hour (not subscripted), and then aggregated over years.[11] For simplicity, we temporarily ignore the losses associated with the physical flow on the interconnector, but take them into account in the empirical analysis.

3.1 The CPS cost pass-through

Adding the CPS raises short-run marginal costs of electricity generation, but generators in H may absorb some of the tax by marking up their offers by a smaller or larger amount if the market is imperfectly competitive, depending on the shape of the residual demand curve. In this case and in the absence of any cross-border trade, the cost pass-through of the CPS would then differ 100%. Under proportional mark-up pricing (Newbery and Greve, 2017) any cost shock would also be marked up, and the cost pass-through would be more than 100%.

Our post-econometric analysis allows us to estimate Δp^H, the increase in the GB wholesale price when no trading takes place. This enables us to measure the domestic cost pass-through as a percentage of the system marginal cost increase. A pass-through rate significantly different from 100% would cast doubt on the competitive assumption and possibly change domestic deadweight losses as output responds to the CPS. We put this to one side for the moment.

In a closed competitive market, assume that coal and gas are the only marginal fuels. At the margin, the short-run marginal costs (SRMC) of generating electricity from coal and gas (the EUA cost included) are c_C and c_G respectively, assumed unchanged by the CPS. Without the

[8] Increased exports might allow an increase in constrained-off surplus wind, but these are only likely when the country is already exporting and limited by interconnector capacity.

[9] In the very short run, it may induce changes in the pattern of storage, but assuming that storage is efficiently used over the course of the day its total will not change and so will not affect the argument.

[10] The Market Stability Reserve removes the surplus EUAs, making reduction by one country effectively a reduction of global CO_2 emissions. Given this, the EU ETS operates as a carbon tax, for which this assumption would be valid.

[11] Output and trade are only measured for hours with positive fossil generation in the Home country, as there can only be changes in the residual demand and import in such periods. In periods of surplus foreign renewables the Foreign residual demand is constrained to zero, $m_0 = K$ and again there will be no change in imports with the CPS and so such periods will also be excluded.

CPS, if the marginal share of coal is α_0, the electricity price in H is the system SRMC:

$$p_0^H = \alpha_0 c_C + (1-\alpha_0)c_G. \tag{1}$$

The CPS (τ, €/tCO_2) raises the system SRMC. If τ switches the merit order and hence the marginal share of fossil fuels, H's system SRMC with τ is

$$p_1^H = \alpha_1(c_C + e_C \cdot \tau) + (1-\alpha_1)(c_G + e_G \cdot \tau), \tag{2}$$

where α_1 is the marginal share of coal with the CPS, and e_C and e_G are emissions per megawatt hour of electricity (MWh_e) generated by marginal coal and gas. In this closed competitive market, the CPS has raised the electricity price by

$$\begin{aligned} p_1^H - p_0^H &= \tau \cdot [\alpha_1 \cdot e_C + (1-\alpha_1) \cdot e_G] + (c_C - c_G) \cdot (\alpha_1 - \alpha_0) \\ &= \tau \cdot \mu_1^H + (c_C - c_G) \cdot \Delta\alpha, \end{aligned} \tag{3}$$

where $\mu_1^H = [\alpha_1 \cdot e_C + (1-\alpha_1) \cdot e_G]$ denotes the Marginal Emission Factor (MEF, the CO_2 released from the last unit of electricity generated in MWh_e/tonne CO_2) of H with the CPS applying, and $\Delta\alpha = \alpha_1 - \alpha_0$ is the change in the marginal share of coal.

Equation (3) suggests that if the CPS does not change the marginal share of coal and $\Delta\alpha = 0$, or if the SRMCs of coal and gas are close without the CPS and $c_C - c_G \approx 0$, the impact of the CPS on the domestic electricity price would be $\mu_1^H \cdot \tau$. Otherwise, given that normally coal is the cheaper fuel without the CPS ($c_C - c_G < 0$), and that from Chyong et al. (2020) the marginal share of coal has decreased with the CPS ($\Delta\alpha < 0$), the impact of the CPS on the electricity price should be higher than $\mu_1^H \cdot \tau$. Using the data and results from Chyong et al. (2020), we can estimate both $(c_C - c_G)$ and $\Delta\alpha$, which enables us to further examine whether the CPS has been fully passed through to the GB's wholesale electricity price.

3.2 Impact on electricity trade

Interconnectors complicate this simple single market story. Without capacity limits, the increase in H's electricity price will change flows until the prices in both markets equate. With capacity limit and if flows do not change due to an existing capacity constraint, there will be no additional distortion. However, if flows do change, there will be additional deadweight losses. If demand is inelastic, the deadweight loss will be the difference in the total cost of generation with and without the CPS.

We use geometric expositions to clarify the problem, and distinguish five possible cases of trade:

(a) trade is constrained without the CPS but is unconstrained with the CPS (H initially exports): $p_0^H < p_0^F$ and $p_1^H = p_1^F$;

(b) trade is constrained with and without the CPS, but the direction of trade changes: $p_0^H < p_0^F$ and $p_1^H > p_1^F$;

(c) trade is unconstrained with and without the CPS: $p_j^H = p_j^F$;

(d) trade is unconstrained without the CPS but constrained with the CPS: $p_0^H = p_0^F$ and $p_1^H > p_1^F$;

(e) trade and its direction are unaffected by the CPS, as it is constrained by interconnector capacity with and without the CPS: $p_j^H > p_j^F$, or $p_j^H < p_j^F$.

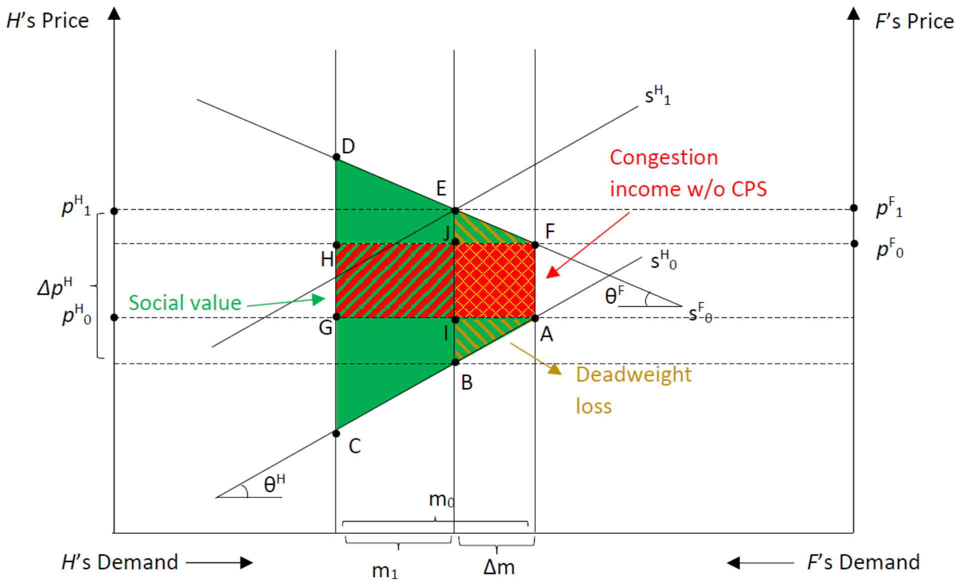


Figure 5: Impact of CPS on imports and deadweight losses, Case (a)

Figure 5 gives a geometric exposition of Case (a). Without the CPS, H's net supply curve[12] is represented by s_0^H and F's supply curve is represented by s_0^F. H exports to F at the full interconnector capacity $m_0 = -K$, with H's prices (p_0^H) lower than F's prices (p_0^F) and congestion income equalling to $R_0 = (p_0^H - p_0^F) \cdot m_0$, or the rectangle AGHF.[13] Under the assumption of zero consumer demand elasticity (i.e. vertical demand curves), the interconnector creates an initial surplus (gains from trade) which is entirely due to a reduction in F's generation costs (the area under F's net supply curve from D to F), offset by an increase in H's cost (the area under H's net supply curve from C to A), or the area of the trapezium ACDF, made up of importer's and exporter's surplus (triangles DFH and ACG, respectively) and the congestion income without the CPS (rectangle AGHF). Given the slopes of the net supply curves are, over the relevant range, θ^H and θ^F respectively for H and F, the social value of trade (when there is nothing to distort trade) is thus

$$S = \frac{1}{2} \cdot (\theta^H + \theta^F) \cdot m_0^2 + m_0 \cdot (p_0^H - p_0^F). \quad (4)$$

With the CPS, H's supply curve shifts upward to s_1^H. Although H is still exporting, the interconnector is now uncongested and the net import increases by Δm. The deadweight loss is defined as the difference between F's increased generation cost (the area under F's net supply

[12]supply from fossil fuels.

[13]The congestion income is the arbitrage gain from buying low and selling high, defined as the product of the interconnector flow and price difference between H and F.

curve from F to E) and H's reduced generation cost (the area under H's net supply curve from A to B). Given θ^H and θ^F, the deadweight loss is the trapezium ABEF, made up of triangles EFJ and ABI and rectangle AIJF. Algebraically,

$$L = \frac{1}{2} \cdot (\theta^H + \theta^F) \cdot \Delta m^2 + \Delta m \cdot (p_0^F - p_0^H). \tag{5}$$

In this case, there is no congestion income with the CPS applying, hence change in congestion income is

$$\Delta R = (p_1^F - p_1^H) \cdot m_1 - (p_0^F - p_0^H) \cdot m_0, \tag{6}$$

where in this case, $p_1^F - p_1^H = 0$.

In Case (b)-(e) similar arguments apply. The social value of the interconnector is due to a reduction in F's generation costs offset by an increase in H's cost where there is no trade distortion, and the deadweight loss is the difference between F's increased generation cost and H's reduced generation cost following the unilateral carbon tax. Finally, the congestion income is the product between price differences and flows. Appendix A.3 gives detailed explanation for each case.

To sum up, in all cases the social value can be expressed as equation (4), the deadweight loss from the trade distortion can be expressed as equation (5), and the change in congestion income can be expressed as equation (6). Given this, both the social value and deadweight losses are (linearly) positively correlated with the price difference where the CPS is not applied, and (quadratically) positively correlated with the interconnector capacity (which determines the magnitudes of m_0 and Δm). The change in congestion income would depend on flows and price differences with and without the CPS.

3.3 Global impact

The CPS has substantially reduced domestic CO_2 emissions from electricity. However, changes in trade between H and F could potentially undo some part of H's CO_2 emission reduction. For simplicity, assume that the fuel mix and the marginal fuel shares abroad do not change with net exports (i.e. they are unaffected by the CPS). This would be plausible if there were no internal transmission constraints on the Continent, as changes in their exports would be a very small fraction of total generation. Given this, the foreign country's MEF (μ^F) remains unchanged and the slope of its net supply curve is also unchanged. Also assume that the CPS has little short-run impact on non-EU countries other than through changing global emissions.

ΔW is the change in global welfare that increases from a fall in total emissions. If the Social Cost of Carbon (SCC)[14] is C, and deadweight loss is L defined in (5), then,

$$\Delta W = (\Delta E + \varepsilon) \cdot C - L \tag{7}$$

where ΔE denotes the emission reduction due to changes in H's fuel mix (holding imports

[14] The SCC is defined as the present discounted social cost of the damage caused by emitting one tonne of carbon (more usually measured per tonne of CO_2).

fixed), and ε denotes the emission reductions due to H's increased import from F. Chyong et al. (2020) uses a Unit-Commitment Dispatch model to give estimates of GB's emission reduction from CPS in 2015 while holding imports fixed, while in this study we focus on the second part of emissions reduction, ε. With the CPS, the MEFs are μ_1^H and μ^F, so the emission reduction from trading is

$$\varepsilon = (\mu_1^H - \mu^F) \cdot \Delta m. \tag{8}$$

The next challenge is to identify the effective SCC. The US estimate ranges from $\$_{2018}14/tCO_2$ (5th percentile, uprated by the CPI) to $\$_{2018}130/tCO_2$ (95th percentile) with an average at 3% discount rate of $\$_{2018}45$(€38)/$tCO_2$ (US EPA, 2016). At the lower discount rate preferred by Stern Review (2006) and many others, the SCC would be higher. The UK Government's figure[15] for sectors not covered by the ETS (i.e. the full SCC) in 2020 was $£_{2018}70$ (€79)/tCO_2.

The 2019 average GB carbon price for fossil generation was €45/tCO_2, greater than both the average US SCC and the EU ETS level of €20/tCO_2. Even if the 2019 GB price is considered a defensible SCC, from 2013 the annual average GB price has steadily risen from €8.23/tCO_2 at which level it would be considerably below the US SCC. In our analysis, to calculate the global surplus from the CPS, we take the 2019 British carbon price as the SCC, i.e. $C =$ €45/tCO_2. Clearly it is simple to adjust ΔW for other values of the SCC, C.

3.4 Other distributional impacts

There are other distributional impacts from the CPS. As prices increase in both countries, some producers gain and consumers lose.[16] In the home country, the government receives additional tax revenue from the CPS, and both countries receive EUA revenues that change with output. Estimating these distributional impacts requires knowledge about market structures of both markets, and perhaps simulation techniques are preferable to econometric methods. We leave their estimation for future research.

4 Econometric Models

This section presents the econometric specifications to study the impact of interconnector flows and the British CPS on the domestic and foreign day-ahead electricity prices. The period for our econometric analysis starts on 4 February 2014, when the North-Western Europe market coupling went live, to 30 September 2018, when GB first became coupled with the island of Ireland. During this period, no new interconnectors were commissioned, and the capacity of fossil plants, especially coal, was stable in GB, France, and The Netherlands. Over the period, the British CPS rose from £4.94/tCO_2 to £9.55/tCO_2 and then stabilised at £18/tCO_2, providing a sufficient number of observations for different levels of the CPS. Data availability[17]

[15] https://www.forestresearch.gov.uk/research/review-of-approaches-to-carbon-valuation-discounting-and-risk-management/current-uk-government-guidance-for-social-value-of-carbon/

[16] H's marginal fossil suppliers may not gain from the higher domestic wholesale price but H's other suppliers will gain.

[17] We are unable to obtain the Dutch day-ahead or actual wind and load data for the period before 2015.

makes IFA, the interconnector between GB and France, the main focus, though we provide some less reliable estimates for BritNed, the link between GB and the Nertherlands. This section introduces the simplest specification with neither peak and off-peak heterogeneity nor interaction terms. ISection 6 gives the simple results and also examines heterogeneity between peak and off-peak and includes interaction terms.

One of our major challenges in estimating the impact of flows on electricity prices is that the day-ahead market is an implicit auction, which means the domestic and foreign prices and the interconnector flows are determined simultaneously, raising the issue of simultaneity. Finding proper instrumental variables for the day-ahead flows is difficult because under market coupling, the day-ahead flows are only determined by the day-ahead price differences, i.e. the dependent variables. To circumvent this issue, in the post-estimation part we use the marginal effects of wind on prices as proxies for the marginal effects of flows. Changes in imports should be similar to changes in wind generation in their impact on fossil generation.

As electricity supply has to meet demand at every moment, prices are highly volatile. To deal with this, we implement the Multivariate Generalised Auto-Regressive Conditional Heteroskedasticity (M-GARCH) model (Silvennoinen and Teräsvirta, 2008), which accounts for variations in both the mean and volatility of electricity prices. M-GARCH has been widely used to model day-ahead electricity prices (e.g. Kirat and Ahamada, 2011; Anna-Phan and Roques, 2018).

As hourly electricity prices in most European countries for the next day are all set simultaneously in the pan-European day-ahead auction, the data generation process of the prices indicates that it would be problematic to treat them as univariate time series with hourly frequency. For the same reason, within a day the price for any hour does not carry much information about the next hour (Keppler, 2014; Würzburg et al., 2013; Sensfuss et al., 2008). Therefore, for each country we aggregate to give daily averaged day-ahead prices. For our main case the *mean equation* of the M-GARCH model is

$$\boldsymbol{y}_t = \boldsymbol{\mu} + \boldsymbol{\Gamma}\boldsymbol{X}_t + \boldsymbol{\varepsilon}_t, \ \ \boldsymbol{y}_t = \left(P_t^{GB}, P_t^{FR}\right)', \tag{9}$$

where $\boldsymbol{y}_t$ is a vector of day-ahead GB and French prices, and t represents days. $\boldsymbol{X}_t$ is a $k \times 1$ vector of exogenous covariates, including the day-ahead forecast[18] of wind and nuclear generation for both countries, electricity load (i.e. demand) for both countries, coal and gas prices, the EUA price, the day-ahead scheduled interconnector capacity and most importantly, the British CPS. We also include dummy variables representing the days of the week and the quarters of the year.[19]

We do not include auto-regressive terms of the dependent variables in the regression because first, the electricity wholesale markets in GB and France are workably competitive (CMA, 2016; Pham, 2015). This means that bidding behaviour is primarily driven by the short-run

[18] Whenever the forecast data is unavailable, we use the actual data as a proxy.

[19] The yearly dummy variables are not included mainly because it can substantially save computational time, especially for the more complicated specifications such as Regression (iii) in Table 2. Also, almost all covariates carry information of (yearly) trends and drifts (if any), which weakens the importance of the yearly dummies. Lastly, including yearly dummies in the regressions have negligible effects on the estimation results.

marginal cost, instead of the market outcome from days before. Second, including day-of-week dummy variables allow us to effectively capture the difference in price patterns between weekdays and weekends. The reason that the lagged fuel and carbon prices are also excluded from the model is that the market participants in both GB and France have many years of experience, and can observe the daily prices of each before making their bids.

All covariates can be treated as exogenous. Wind generation depends on weather, and electricity load is inelastic to prices in the short-run (Clò et al., 2015). Nuclear generation is also exogenous as it runs unless an outage occurs.[20] Although some studies have found that dynamic interactions among fuel, carbon, and electricity prices may play an important role in price formation (Knitell and Roberts, 2005), we argue that fuel and carbon costs (EUA prices in this case) are more likely to be affected by the EU-wide demand by the much larger covered sector for EUAs, a claim supported statistically by Guo and Castagneto Gissey (2019). The authors also find the exchange rate between Euro and Sterling is exogenous with respect to electricity prices. Finally, the scheduled interconnector capacity is only influenced by outages, maintenance or network limitations and so can also be treated as exogenous.

We expect wind and nuclear generation to reduce electricity prices and load to raise prices. As GB has consistently been a net importer of electricity from the Continent, we expect interconnector capacity to lower the GB price and raise foreign prices. We also expect the fuel and EUA prices to raise electricity prices. The impact of fuel and the EU carbon costs on electricity prices depends on the (marginal) fuel mix in the market. During 2013-2017, fossil fuel provided more than 80% of GB's marginal generation (Chyong et al., 2019; Staffell, 2017), while the marginal generation in France has heavily relied on hydro and imports. Therefore, one might expect fuel costs and EUA prices to have a stronger impact on the GB price than the French price. However, marginal imports of France come from in other fossil-fuel intensive Continental markets (e.g. Germany, Belgium, Spain and Italy), which could also influence the French price, potentially boosting the effect of fuel and EUA prices on the French price.

Our estimates of the impact of the CPS on the prices are conditional on interconnector capacity but *unconditional* on interconnector flows, meaning that the coefficients for the CPS can only be interpreted as the estimates of the diluted (by trade) impact of the CPS on both GB and French prices. As other EU countries have not yet introduced a carbon tax similar to the CPS, the higher GB carbon tax result in foreign countries exporting more electricity to GB, which in turn lowers the GB price and raises the foreign price. We therefore expect the CPS to have positive impacts on both GB and French prices, though its effect on the GB price should to be much higher.

To control for dynamic heteroskedasticity, we assume $\boldsymbol{\varepsilon}_t$ to be conditionally heteroskedastic:

$$\boldsymbol{\varepsilon}_t = \boldsymbol{H}_t^{1/2} \boldsymbol{\eta}_t \tag{10}$$

given the information set $\mathbf{I}_{t-1}$, where the 2×2 matrix $\boldsymbol{H}_t = [\sigma^2_{ij,t}], \forall i, j = 1, 2$, is the conditional covariance matrix of $\boldsymbol{\varepsilon}_t$. $\boldsymbol{\eta}_t$ is a normal, independent, and identical innovation vector with zero

[20] Although the French nuclear power may reduce output off-peak, aggregating the hourly observations to daily can effectively deal with the potential endogeneity.

means and a covariance matrix equalling to the identity matrix, i.e. $E\boldsymbol{\eta}_t\boldsymbol{\eta}_t' = \boldsymbol{I}$.

We use the Constant Conditional Correlation (CCC)[21] GARCH(1,1) model proposed by Bollerslev (1990), where the conditional correlation matrix, $\boldsymbol{H}_t$, can be expressed as:

$$\boldsymbol{H}_t = \boldsymbol{D}_t^{1/2}\boldsymbol{R}\boldsymbol{D}_t^{1/2}, \tag{11}$$

where $\boldsymbol{R} = [\rho_{ij}]$ is a 2×2 time-invariant covariance matrix of the *standardised* residuals $\boldsymbol{D}_t^{-1/2}\boldsymbol{\varepsilon}_t$. $\boldsymbol{R}$ is positive definite with diagonal terms $\rho_{ii} = 1$. $\boldsymbol{D}_t = [d_{ij,t}]$ is a diagonal matrix consisting of conditional variances with $d_{ii,t} = \sigma^2_{ii,t}$, and $d_{ij,t} = 0$ for $i \neq j$.

The model assumes the conditional variances for electricity prices follow a univariate GARCH(1,1) process and the covariance between prices is given by a constant-correlation coefficient multiplying the conditional standard deviation of the price differentials:

$$\sigma^2_{ii,t} = s_i + \alpha_i\varepsilon^2_{i,t-1} + \beta_i\sigma^2_{ii,t-1}, \tag{12}$$

$$\sigma^2_{ij,t} = \rho_{ij}\sqrt{\sigma^2_{ii,t}\sigma^2_{jj,t}}, \tag{13}$$

where s_i is a constant term, α_1 is the ARCH parameter capturing short-run persistence and β_1 is the GARCH parameters capturing long-run persistence.

One advantage for the M-GARCH model is that it allows for the existence of missing data, where the missing dynamic components are substituted by the unconditional expectations. The model is estimated by Maximum Likelihood Estimation. As noted above, we assume no autoregressive terms. This saves considerable computational time by reducing the number of unknown parameters.

5 Data

Table 1 gives summary statistics for all variables. The day-ahead price for France is collected from Epex Spot, and the DAM price for GB comes from the Nord Pool Market Data Platform. The French System Operator (RTE) provides forecasts of hourly French electricity load and wind generation, as well as the actual hourly French nuclear generation. While we are unable to find the day-ahead forecast of GB load and wind generation over the whole period, we use the actual half-hourly data from National Grid as proxies. The half-hourly GB nuclear generation is collected from the Elexon portal. ENTSO-E provides the day-ahead forecasted transfer capacity of interconnectors. All (half-)hourly data are aggregated to daily averages.

The daily UK National Balancing Point (NBP) price[22] and the EUA price are collected from the InterContinental Exchange (theice.com), and the daily coal price is collected from the CME group, representing coal prices at global level. In order to count in the transportation cost of coal into power stations, quarterly averages of the daily prices are subtracted from the BEIS

[21] The Wald test suggests to use the CCC model instead of a more complicated Dynamic Conditional Correlation (DCC) model, and both models provide very similar estimation results.

[22] An alternative is to use the Dutch natural gas price at the Title Transfer Facility (TTF) Virtual Trading Point. However, as the European natural gas markets are rather liquid, the two natural gas prices are extremely close.

Table 1: Summary Statistics

Variable	Unit	Abbr.	Mean	S. D.	Min.	Max.
GB day-ahead price	€/MWh	P^{GB}	53.80	9.72	33.33	199.98
French day-ahead price	€/MWh	P^{FR}	39.86	14.82	2.98	125.92
IFA day-ahead capacity	GW	IC^{IFA}	1.77	0.38	0.43	2.00
GB load	GW	D^{GB}	31.31	4.44	20.82	42.91
French load	GW	D^{FR}	53.36	10.62	34.82	87.97
GB wind	GW	W^{GB}	2.97	1.92	0.14	10.16
French wind	GW	W^{FR}	2.28	1.49	0.33	10.54
GB nuclear	GW	W^{GB}	7.32	0.76	4.25	8.99
French nuclear	GW	W^{FR}	44.93	6.37	29.94	60.61
CPS	€/tCO$_2$	CPS	19.36	4.99	5.88	26.06
Coal plant var. cost	€/MWh$_e$	VC^{COAL}	28.19	4.48	17.44	37.79
Gas plant var. cost	€/MWh$_e$	VC^{CCGT}	34.50	6.75	20.29	54.47
EUA price	€/tCO$_2$	EUA	7.61	3.58	3.99	25.19

quarterly "average prices of fuels purchased by the major UK power producers".[23] The raw coal price data is then adjusted by adding this margin.[24] All fuel prices are first converted to Euros per megawatt hours of heat (€/MWh$_{th}$) using daily exchange rates (from the real-time FX). Then, assuming the thermal efficiency for coal-fired power plants is 35.6% and for CCGTs is 54.5% (Chyong et al., 2019), we transform the fuel prices into €/MWh$_e$, namely Euros per megawatt hours of electricity generated.[25] These are the variable costs (i.e. short-run marginal cost) of electricity generated from coal and gas plants without counting in carbon prices.[26] In the rest of this paper, MWh and MWh$_e$ are used inter-changeably.

6 Results

In our regressions, outliers for day-ahead electricity prices are defined as values exceeding four standard deviations of the sample mean and are removed and treated as missing data. Several validity tests are applied. Wald tests examine whether the more complicated Dynamic Conditional Correlation (DCC) models instead of the proposed Constant Conditional Correlation (CCC) models are necessary (Tse and Tsui, 2002), and the test statistics suggest using CCC models. Estimates of the correlation coefficients, ρ_{ij} in equation (11) are within the interval of $(-1,1)$, and estimates of the conditional variance matrices, $\boldsymbol{H}_t, \forall t$ are positive definite, ensuring the validity of the M-GARCH model. Table 2 presents the estimation results of the mean

[23] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/790152/table_321.xlsx

[24] We consider the UK coal price a much better proxy of the EU coal prices than the raw data from the CME group.

[25] Dividing €/MWh$_{th}$ by the thermal efficiency gives €/MWh$_e$.

[26] Although the day-ahead prices, variable costs, the EUA price, as well as the CPS (in Euro) are non-stationary process, the Johansen tests suggest that the non-stationary variables are cointegrated. As a results, using levels (instead of first differences) to run regressions will be consistent (Johansen and Juselius, 1990).

equations.[27]

Table 2: M-GARCH results

	Unit	(i)	(ii)		(iii)	
GB DAM prices			Off	Peak	Off	Peak
GB wind	GW	-0.881^{***}	-0.410^{***}	-0.965^{***}	-1.162^{***}	-0.826^{***}
		(0.039)	(0.055)	(0.036)	(0.113)	(0.078)
GB wind ×CPS Dummy	GW				0.873^{***}	-0.221^{*}
					(0.114)	(0.086)
French wind	GW	-0.054	-0.219^{***}	0.153^{***}	-0.210^{***}	0.056
		(0.049)	(0.063)	(0.038)	(0.057)	(0.043)
IFA capacity	GW	-0.836^{***}	-0.071	-2.553^{***}	0.134	-1.896^{***}
		(0.241)	(0.203)	(0.145)	(0.183)	(0.207)
Coal price	€/MWh$_e$	0.345^{***}	0.426^{***}	0.336^{***}	0.429^{***}	0.053
		(0.021)	(0.024)	(0.016)	(0.069)	(0.056)
Coal price ×CPS Dummy	€/MWh$_e$				-0.145^{*}	0.335^{***}
					(0.063)	(0.056)
Gas price	€/MWh$_e$	0.825^{***}	0.702^{***}	0.945^{***}	0.609^{***}	0.930^{***}
		(0.015)	(0.019)	(0.015)	(0.034)	(0.034)
Gas price ×CPS Dummy	€/MWh$_e$				0.201^{***}	-0.114^{**}
					(0.041)	(0.043)
EUA	€/tCO_2	0.507^{***}	0.554^{***}	0.409^{***}	0.994^{***}	1.039^{***}
		(0.024)	(0.029)	(0.024)	(0.214)	(0.175)
EUA ×CPS Dummy	€/tCO_2				-0.479^{*}	-0.565^{**}
					(0.219)	(0.178)
CPS	€/tCO_2	0.595^{***}	0.545^{***}	0.633^{***}	0.366^{***}	0.584^{***}
		(0.013)	(0.018)	(0.015)	(0.055)	(0.046)
French DAM prices						
GB wind	GW	-0.135	-0.226^{**}	-0.131	-0.238^{**}	-0.146^{*}
		(0.076)	(0.081)	(0.070)	(0.081)	(0.070)
French wind	GW	-1.817^{***}	-1.896^{***}	-1.467^{***}	-1.898^{***}	-1.485^{***}
		(0.089)	(0.092)	(0.083)	(0.092)	(0.083)
IFA capacity	GW	-0.674	-1.505^{***}	-1.047^{**}	-1.465^{***}	-0.942^{**}
		(0.379)	(0.314)	(0.357)	(0.312)	(0.359)
Coal price	€/MWh$_e$	0.607^{***}	0.531^{***}	0.494^{***}	0.516^{***}	0.482^{***}
		(0.035)	(0.043)	(0.043)	(0.043)	(0.043)
Gas price	€/MWh$_e$	0.690^{***}	0.317^{***}	0.550^{***}	0.323^{***}	0.538^{***}
		(0.037)	(0.036)	(0.037)	(0.036)	(0.038)
EUA	€/tCO_2	0.611^{***}	0.979^{***}	0.913^{***}	1.005^{***}	0.949^{***}
		(0.060)	(0.064)	(0.069)	(0.063)	(0.068)
CPS	€/tCO_2	0.320^{***}	0.046	0.098^{*}	0.050	0.103^{**}
		(0.039)	(0.037)	(0.039)	(0.037)	(0.039)
Nuclear outage			YES	YES	YES	YES
No. Obs.		1687	1684		1684	

Standard errors in parentheses. $^{*}p < 0.05$, $^{**}p < 0.01$, $^{***}p < 0.001$.

Regression (i) ignores the heterogeneity between peak and off-peak behaviour. We find the estimated impact of the CPS on the French price is unexpectedly high: a €1/tCO_2 increase in the CPS is associated with a €0.32/MWh increase in the French price, more than a half of its impact on the GB price. Further analysis reveals that even though we have controlled for

[27]The full results are listed in Table A.1.

nuclear generation, the major French nuclear outages (in Q3-Q4 2016 and Q4 2017) have much higher effects on the French prices than during normal outages, and ignoring this effect would result in omitted variable bias.

As a result, in Regressions (ii) and (iii) we add a dummy variable representing periods of severe French nuclear outages. Regressions (ii) and (iii) also separates the day into peak and off-peak, hence $\boldsymbol{y}_t$ of equations (9) now has four dependent variables $(P_t^{GB,P}, P_t^{FR,P}, P_t^{GB,O}, P_t^{FR,O})'$, namely the daily averaged peak and off-peak electricity prices for GB and France. Peak and off-peak have different demands and fuel mix, so the marginal fuel could differ, resulting in different marginal effects on electricity prices. Regression (iii) further adds interaction terms between some of the existing covariates and a dummy variable equalling to one when the British CPS was stabilised at £18/tCO_2 (after April 2015). This is because the high CPS has switched the merit order between coal and gas within the GB electricity dispatch (Chyong et al., 2020), hence after April 2015, wind might displace different fuel types and have different effects on the GB price. For the same reason, the marginal effects of fuel and the EUA prices on the GB price could be different before and after April 2015.

From Regressions (ii) and (iii), we find evidence on both domestic and foreign wind lowering French prices, in agreement with Anna-Phan and Roques (2018). The intuition is that higher foreign wind reduces foreign electricity prices, resulting in higher domestic net import, which further reduces domestic prices. Although Regression (ii) suggests French wind has a positive effect on the GB price during peak periods, the magnitudes is small and the effect disappears in Regression (iii).

We find interconnector capacity of IFA reduces electricity prices in GB, as GB is consistently a net importer from France. The effects are significantly different between peak and off-peak, probably because GB has a convex and monotonically increasing marginal cost curve, as illustrated in Appendix Figure A.2. During off-peak periods, the electricity system is running at base load with a relatively flat marginal cost curve, so a change in the interconnector capacity (hence import) has little effect on the GB price.

Counterintuitively, we find interconnector capacity has a negative effect on French prices as well, for rather complicated reasons. On the one hand, 80% of the French electricity comes from nuclear power stations with close-to-zero marginal costs, and the French electricity market is designed to be an exporter of electricity. Therefore, when the French nuclear stations are producing with full capacity, its electricity supply curve is mostly flat. On the other hand, when France is importing, it is likely because of high demand relative to nuclear output (cold weather, nuclear outages). In those cases, due to its limited capacity of fossil fuels, the French marginal cost curve can be steep where it meets demand, and importing (or increasing interconnector capacity) can substantially reduce the French electricity price. As a result, one may observe interconnector capacity substantially reducing the French prices, even though France exports to GB most of the time. This is not the case between BirtNed's capacity and the electricity price of The Netherlands, who has a much smaller share of nuclear capacity in its electricity system, as illustrated in Appendix A.7.

Electricity prices are positively correlated with both coal and gas prices. However, gas prices are found to have a much stronger impact in GB than France because the GB electricity system relies more heavily on gas. This is especially the case after April 2015, when the CPS has made the GB electricity supply less coal-dependent and more gas-dependent, while in France coal remains relatively cheaper. For both countries, the marginal effects of gas are significantly higher in peak than off-peak periods, consistent with Chyong et al. (2020), who argue that because peak demand is more variable, the more flexible gas plants are preferred to respond to wind and demand changes then.

As GB's electricity generation is less carbon intensive thanks to the CPS, the EUA price has positive but smaller effects on the GB price than the French price (well-connected to a fossil hinterland). The CPS has a positive impact on the French price, consistent with GB importing more electricity from France due to the CPS.

From regression (iii), the marginal effects of wind, fuel prices, and the EUA price are substantially different before and after the 2015 rise in the CPS. Before then, wind had a very substantial effect on GB's off-peak prices, while the high CPS made it less influential, suggesting a much flatter marginal cost off-peak schedule after April 2015. Because the high CPS has switched coal from base to the mid-merit load, coal is expected to have a stronger impact on the peak than off-peak GB prices, and *vise versa* for gas. Our regression results are in agreement with the theory and find that since April 2015, GB prices rely more heavily on coal during peak periods and more heavily on gas during off-peak periods.

In the rest of this section, Subsections 6.1-6.3 utilises results from Regression (iii) to estimate the counterfactual (i.e. with the CPS not applying) prices and flows of GB and France, the CPS pass-through to the GB electricity price, and the trade distortion between GB and France. Subsection 6.4 discusses the global impact of the CPS, and Subsection 6.5 gives a summary of BritNed, the interconnector between GB and The Netherlands.

6.1 Estimating the counterfactual IFA flows

Table 2 gives the estimated impacts of wind and the CPS on the GB and French electricity prices for both peak and off-peak periods. Appendix A.4 shows how the estimates from Regression (iii) give the counterfactual prices and flows.

Table 3 summarises the average annual (electricity year from 1 April to 31 March) day-ahead electricity prices of GB and France, GB's net import, and congestion income. The differences between the actual and the counterfactual cases are also listed (in the columns denoted with Δ). The counterfactual for the electricity year 2014-2015 removes the CPS of £9.55/tCO_2, while the counterfactual for the electricity years 2015-2018 removes the CPS of £18/tCO_2. The final lines give the averages over 2015-2018.

The CPS increases the GB price and hence net imports, which mitigates the GB price rise somewhat and (slightly) increases the French price. Over 2015-2018, the £18/tCO_2 of CPS has on average raised the GB price by €11.43/MWh (or by 28%) and the French price by €1.37/MWh (or 3.5%).[28] Perhaps unexpectedly, without the CPS, GB's net imports for IFA

[28] This means, on average, a €1/tCO_2 increase in the CPS is associated with a €0.06/MWh increase in the French price, consistent with our estimates in Table 2. Therefore, it is perfectly reasonable to assume that the CPS has no direct impact on the French price other than through trading via IFA in Step 2 of Appendix A.4.

Table 3: IFA: the counterfactual prices, flows, and congestion income

Electricity years	**GB Prices (€/MWh)**			**French Prices (€/MWh)**		
	w. CPS	w/o CPS	Δ	w. CPS	w/o CPS	Δ
14-15	€52.22	€46.20	€6.02	€36.39	€35.69	€0.70
		(0.44)	(0.44)		(0.06)	(0.06)
15-16	€53.24	€40.40	€12.85	€34.49	€33.24	€1.25
		(0.88)	(0.88)		(0.14)	(0.14)
16-17	€51.76	€40.70	€11.06	€43.22	€41.93	€1.29
		(0.77)	(0.77)		(0.12)	(0.12)
17-18	€52.70	€42.31	€10.39	€42.21	€40.63	€1.58
		(0.71)	(0.71)		(0.14)	(0.14)
Ave.(15-18)	€52.57	€41.14	€11.43	€39.97	€38.60	€1.37
		(0.78)	(0.78)		(0.13)	(0.13)
	GB Net Import (TWh)			**Congestion Income (m €)**		
	w. CPS	w/o CPS	Δ	w. CPS	w/o CPS	Δ
14-15	15.21 TWh	11.29 TWh	3.92 TWh	€243	€164	€79
		(0.33)	(0.33)		(5.04)	(5.04)
15-16	15.52 TWh	8.55 TWh	6.97 TWh	€303	€143	€160
		(0.75)	(0.75)		(7.82)	(7.82)
16-17	8.17 TWh	1.05 TWh	7.12 TWh	€185	€130	€55
		(0.61)	(0.61)		(1.44)	(1.44)
17-18	11.32 TWh	2.57 TWh	8.75 TWh	€194	€123	€70
		(0.75)	(0.75)		(2.75)	(2.75)
Ave.(15-18)	11.67 TWh	4.60 TWh	7.61 TWh	€227	€132	€95
		(0.70)	(0.70)		(3.76)	(3.76)

Standard errors in parentheses.

during 2016-2018 would be close to zero, as the electricity prices between the two countries would be close, caused by French nuclear outages in both winters of 2016 and 2017 and the associated high French prices. During 2015-2018, GB in total imported 23 TWh more electricity from France as a result of the CPS, or about 65% of its actual net import from France. Finally, because the CPS widened the price difference between the two countries, congestion income has risen by €95 m/yr over 2015-2018. This congestion income mostly comes from British consumers, and half of it is transferred to France, because the electricity system operator of French owns half of IFA.

6.2 The CPS pass-through to the GB day-ahead price

The CPS increases the cost of electricity generation and raises GB's day-ahead prices. In a closed competitive economy, the ratio between the increase in the GB price and the increase in the system marginal cost (due to the CPS, holding interconnector flows constant) is the CPS pass-through to the GB day-ahead price. Equation (3) shows the increase in the system SRMC is a function of the MEF with the CPS applying (μ_1^H), the difference of the SRMCs between coal and gas ($c_C - c_G$), and the change in the coal share at margin ($\Delta\alpha = \alpha_1 - \alpha_0$).

Using the data and results from Chyong et al. (2020), during electricity years 2015-2018 the MEFs ($\hat{\mu}_1$) for peak and off-peak are 0.363 and 0.405, respectively.[29] The change in the marginal share of coal ($\widehat{\Delta\alpha}$) during the period is -0.008 and -0.236 for peak and off-peak, respectively.[30] Finally, $(c_C - c_G)$ is estimated to be $-$ €0.323/MWh.[31] Given this, the increase in the system SRMC is €0.366/MWh for peak and €0.481/MWh for off-peak.

The impact of the CPS on the GB electricity price when there is no cross-border trade from Appendix A.4 is estimated to be $\widehat{\Delta p^H} =$ €0.635/MWh (s.e.=0.049) for peak periods and $\widehat{\Delta p^H} =$ €0.346/MWh (s.e.=0.060) for off-peak periods.

Based on this, assuming the estimates from Chyong et al. (2020) has zero standard errors[32] and are independent with this paper, the CPS pass-through rate to GB's peak prices is 173% with a 95% confidence interval of 147-200%, and to GB's off-peak prices is 72% with a 95% confidence interval of 47-96%. The weighted average is 133% with a 95% confidence interval of 108-159%. The higher cost pass-through in peak periods compared to off-peak is consistent with most empirical literature (e.g. Sijm et al., 2006; Jouvet and Solier, 2013; Fabra and Reguant, 2014). Guo and Castagneto (2019) explain this as electricity utilities strategically bid at lower-than SRMC rates during off-peak periods to stay dispatching to avoid the much higher shut-down and re-start costs. On the other hand, to compensate the off-peak losses, utilities need to bid higher-than SRMC rates during peak periods, as high demand and reduced residual capacity allow them to exercise some market power.

Although we reject the null hypothesis that the average cost pass-through of the CPS is 100% at 5% significant level, if Chyong et al. (2020) have under-estimated the individual fuel emissions factors, then our cost-pass through rates would be over-estimated. Fabra and Reguant (2014) are unable to reject full pass-through except for off-peak hours, using more detailed micro-data than this study.

6.3 Market distortion from IFA

We can use the counterfactual prices and flows estimated in Section 6.1 to estimate IFA's social value from trading and deadweight losses from asymmetric carbon taxes, as discussed in Section 3.2. In addition, we also estimate the UK Government's losses in carbon-tax revenue from the GB generation displaced by increased imports over IFA. (Details are presented in Appendix A.5.)

[29] Chyong et al. (2020)'s period of estimation is 2012-2017 in the Appendix, here we assume the MEF for GB in Q1 2018 is the same as that in Q1 2017. These estimated MEFs use rather low emission factors as they ignore any upstream emissions (from mine/well-head to power station). Using MEFs from other studies may give somewhat different results.

[30] Chyong et al. (2020) demonstrate that the marginal share of coal/gas is a function of price differences between the SRMC of coal and gas. The price differences is $-$ €0.32/MWh without the CPS, and €11.55/MWh with CPS. Given this, $\alpha_0 = 0.356$ for off-peak and 0.229 for peak; $\alpha_1 = 0.120$ for off-peak and 0.221 for peak.

[31] Precisely, using the notation in Table 1, $SRMC^j = VC^j + e^j \cdot EUA$, $j \in \{coal, ccgt\}$, where e^j is the emission factor which takes the value of 0.871 for coal and 0.337 for gas, consistent with Chyong et al. (2020).

[32] Chyong et al.'s estimates have much smaller standard errors, we assume that parameters whose values are taken from them have zero standard error.

Table 4: IFA: surplus, distortion and losses

Electricity years	**Social Value (m €)**	**Deadweight Loss (m €)**	**GB CPS Rev. Loss (m €)**
14-15	€209	€13.4	€20.2
	(5.27)	(2.10)	(1.74)
15-16	€187	€39.8	€69.7
	(8.03)	(7.23)	(7.52)
16-17	€164	€41.5	€55.7
	(1.51)	(6.32)	(4.99)
17-18	€167	€46.0	€61.2
	(2.95)	(7.58)	(5.37)
Ave. 15-18	€173	€42.4	€62.2
	(3.80)	(7.04)	(5.93)

Standard errors in parentheses.

Table 4 lists the social value, deadweight loss, and carbon-tax revenue loss. During 2015-2018, the average deadweight loss from the trade distortion is €42.4 m/yr, about 24% the average social value (€173 m/yr). The average loss in the CPS tax revenue is €62.2 m/yr in the case of IFA, or about 6% of the 2017 CPS tax receipts.

6.4 Carbon leakage and the impact on global welfare via IFA

From Section 3.3, IFA's carbon emission reduction from the high import (ε) is determined by the difference of the MEF between GB and France ($\mu_1^H - \mu^F$) and the change in GB's imports from France (Δm). Appendix A.4 estimates the MEF for France is $\hat{\mu}^F = 0.46$, and Chyong et al. (2020) provide the MEF for GB is $\hat{\mu}_1^H = 0.38$. Then, the carbon leakage to France is about 3.5 $mtCO_2$/yr. In total, both country has emitted roughly 0.6 million tonnes more CO_2 per year due to the higher GB import. If we take the British carbon price in 2019 as the social cost of carbon (C= €45/tCO_2), the social cost of this increased emission is about €27 million.

Chyong et al. (2020) run a Unit-Commitment dispatch model of the 2015 GB power system to estimate that the £18/tCO_2 CPS reduces emission by 44.5 $mtCO_2$/year. Thus about 1.3% of the CO_2 emission reduction from the CPS is undone by France. From equation (7), the estimated total increase in global welfare from the CPS is about €2 bn/yr, hence the distortion from IFA trade (i.e. the deadweight loss caused by the CPS) is only about 2% of this welfare change.

6.5 BritNed: the interconnector between GB and The Netherlands

Appendix A.7 gives estimates of the impact of the CPS and wind on the GB and Dutch electricity prices, and the estimated counterfactuals for BritNed. The CPS on average raised the Dutch wholesale price by €1.02/MWh, or 2.8%. About 63% (4.77 TWh) of GB's actual net import from The Netherlands is due to the CPS, and congestion income almost doubled (from €59 m/yr to €117 m/yr). The social value of BritNed is about €77 m/yr, and the deadweight loss from unilateral carbon taxes is €39 m/yr, about half of the social value and about the same size of the IFA loss (which is twice the capacity). The UK Government lost about €39.2 million in carbon tax revenue, about 4% of its total CPF receipts in 2017.

Carbon leakage to The Netherlands is about 1.6 mtCO_2/yr. Since gas is the marginal fossil fuel in The Netherlands, the two countries' total emission would actually be reduced by 0.2 mtCO_2 per year compared with the zero CPS scenario. This reduction of CO_2 emission is worth about €9 m/yr, partly offsetting the French leakage.

7 Conclusions and Policy Implications

Market coupling ensures the efficient use of interconnectors so that the higher-price market always imports electricity from the lower-price market. Unilateral carbon taxes distort trade if they alter interconnector flows, resulting in deadweight losses. In all cases, carbon taxes transfer revenue abroad at a cost to the domestic economy.

This paper investigated the impact of such carbon taxes on cross-border trade of electricity, both theoretically and empirically. We show geometrically and analytically how the asymmetric carbon tax distorts cross-border electricity trade, and discuss the global impact of the CPS. Empirically, taking the British Carbon Price Support (CPS, a tax) as a case study, we estimate the counterfactual (without the CPS) electricity prices and flows of the connected countries, and further examine the impact of the CPS on GB's net import and congestion income. In addition, we also estimate the social value from cross-border electricity trading, the deadweight loss from asymmetric carbon taxes, the carbon leakage due to untaxed imports, and the global emissions impact of the CPS.

Our estimates show that during electricity years 2015-2018, the CPS increased the GB day-ahead price by €11.43/MWh (about 28% of the GB wholesale price) after allowing for displacement by cheaper imports. The CPS increased imports by 7.6 TWh/yr from France and by 4.8 TWh/yr from The Netherlands (in total, about 4% of the GB annual electricity demand), thereby reducing carbon tax revenue by €62 m/yr from IFA and by €39 m/yr from BritNed (in total, about 10% of the 2017 CPS tax receipts). Congestion income for IFA was increased by €95 m/yr and for BritNed's by €58 m/yr (in total, by 80% relative to the zero CPS case). The social value of interconnectoris around €173 m/yr for IFA and €77 m/yr for BritNed, but the deadweight loss due to the CPS is €42 m/yr for IFA and €39 m/yr for BritNed. In total, the deadweight loss from the CPS accounts for 4% of the global welfare gain from the CPS (mainly from reduced coal burn in GB) at €2 billion/yr. The CPS has also raised the French wholesale price by 3.5% and the Dutch wholesale price by 2.8%. As foreign electricity does not yet bear a CPS, imports from France undo 1.3% of the CO_2 emission reduction partly compensated by -0.4% from The Netherlands (adding to net 0.9%), and the net social cost of this leakage is about €18 m/yr.

The results confirm that the British CPS raised the GB spot price, reduced the convergence of cross-border electricity prices and increased GB imports of electricity. Second, the increase in congestion income (mostly) comes from GB electricity consumers but is equally allocated to both Transmission System Operators as owners of the interconnectors. This increased congestion income could over-incentivise further investment in additional interconnectors, at least to carbon-intensive markets lacking such carbon taxes. Third, following GB's increased imports, both French and Dutch day-ahead prices have increased somewhat. That raised their producer surplus but increased consumer electricity costs. Fourth, the objective of the British CPS is to reduce British CO_2 emissions and incentivise low-carbon investment, but this is partly subverted by increased imports of more carbon-intensive electricity from France. Finally, asymmetric carbon taxes in two connected countries incur deadweight losses, resulting in less efficient cross-border trading.

Despite the CPS distorting cross-border electricity trading, it has significantly reduced GB's greenhouse gas emissions from electricity generation. On 21 April 2017, GB power generation achieved the first-ever coal-free day. When the UK introduced the CPF, the hope was that other EU countries would follow suit to correct the failures of the Emissions Trading System, at least for the electricity sector. The case for such an EU-wide carbon price floor is further strengthened by the desirability of correcting trade distortions.

A Appendices

A.1 Load and Supply Curves

Figure A.1 shows the average daily load curves for GB, France, and The Netherlands during 2015-2018, at Coordinated Universal Time (UTC). To facilitate comparison, we standardise each curve by dividing its hourly loads by its maximum load. The dashed vertical lines divide the loads into peak and off-peak

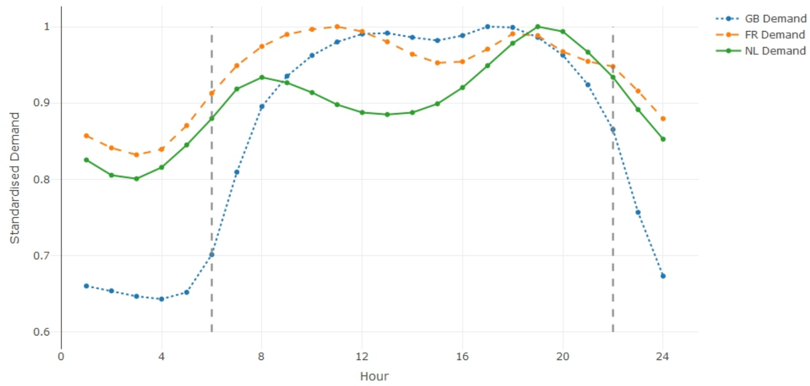


Figure A.1: Standardised Daily Average Load Curves, 2015-2018, UTC

Figure A.2 plots an electricity market with a convex supply curve. During off-peak periods when exports shift net demand from ND_0^{OFF} to ND_1^{OFF}, the spot price decreases by only a small amount.

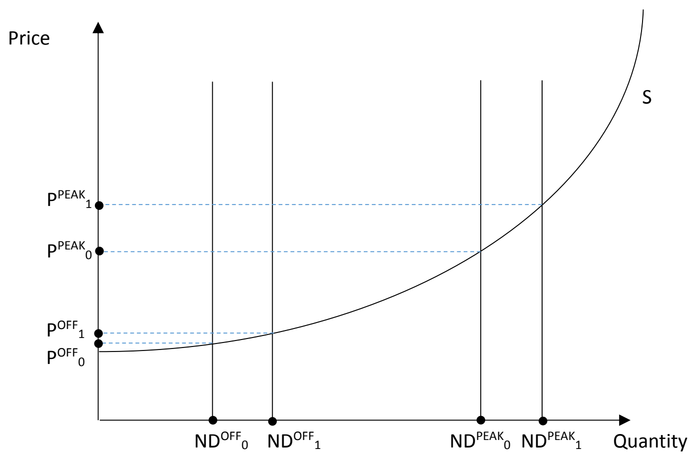


Figure A.2: A Market with a Convex Supply Curve

A.2 M-GARCH Rest of Table 2 for IFA

Table A.1 shows the M-GARCH results for other covariates and the ARCH and GARCH terms, as a continuation of Table 2.

Table A.1: M-GARCH Results (Cont'd)

		Mean Equations				
	Unit	(i)	(ii)		(iii)	
Great Britain			Off	Peak	Off	Peak
(Constant)		-6.249^{***}	-16.38^{***}	-5.064^{***}	-10.91^{***}	-4.147^{*}
		(1.639)	(1.932)	(1.129)	(2.100)	(1.953)
GB load	GW	0.470^{***}	0.857^{***}	0.404^{***}	0.822^{***}	0.488^{***}
		(0.044)	(0.078)	(0.032)	(0.071)	(0.038)
French load	GW	0.061^{***}	-0.086^{**}	0.108^{***}	-0.053^{*}	0.082^{***}
		(0.019)	(0.026)	(0.015)	(0.024)	(0.019)
GB Nuclear	GW	-0.884^{***}	-0.432^{***}	-0.502^{***}	-0.452^{***}	-0.789^{***}
		(0.085)	(0.117)	(0.074)	(0.108)	(0.116)
French Nuclear	GW	-0.063^{**}	-0.060^{*}	-0.108^{***}	-0.101^{***}	-0.062^{*}
		(0.022)	(0.028)	(0.018)	(0.028)	(0.024)
France						
(Constant)		-29.45^{***}	-23.10^{***}	-33.21^{***}	-22.84^{***}	-32.55^{***}
		(3.047)	(2.699)	(2.853)	(2.748)	(2.980)
GB load	GW	0.156	0.000	0.303^{***}	-0.012	0.304^{***}
		(0.114)	(0.111)	(0.067)	(0.111)	(0.067)
French load	GW	1.022^{***}	0.850^{***}	0.895^{***}	0.854^{***}	0.891^{***}
		(0.036)	(0.036)	(0.034)	(0.036)	(0.034)
GB Nuclear	GW	1.023^{***}	1.227^{***}	1.146^{***}	1.236^{***}	1.096^{***}
		(0.168)	(0.167)	(0.181)	(0.172)	(0.190)
French Nuclear	GW	-0.908^{***}	-0.462^{***}	-0.574^{***}	-0.473^{***}	-0.578^{***}
		(0.046)	(0.045)	(0.047)	(0.046)	(0.048)

		Conditional Variance Equations				
Great Britain						
(Constant)		0.400^{***}	2.242^{***}	3.328^{***}	2.227^{***}	1.831^{***}
		(0.080)	(0.265)	(0.239)	(0.265)	(0.284)
ARCH		0.308^{***}	0.609^{***}	1.746^{***}	0.665^{***}	1.132^{***}
		(0.031)	(0.065)	(0.110)	(0.069)	(0.099)
GARCH		0.710^{***}	0.321^{***}	-0.001	0.282^{***}	0.266^{***}
		(0.020)	(0.043)	(0.002)	(0.043)	(0.040)
France						
(Constant)		6.331^{***}	7.019^{***}	5.204^{***}	7.166^{***}	5.428^{***}
		(1.001)	(0.912)	(0.978)	(0.919)	(1.039)
ARCH		0.630^{***}	0.421^{***}	0.303^{***}	0.420^{***}	0.306^{***}
		(0.070)	(0.043)	(0.036)	(0.042)	(0.037)
GARCH		0.244^{***}	0.298^{***}	0.544^{***}	0.291^{***}	0.534^{***}
		(0.061)	(0.060)	(0.055)	(0.060)	(0.057)

Standard errors in parentheses. $^{*}p < 0.05$, $^{**}p < 0.01$, $^{***}p < 0.001$.

A.3 Model Extension

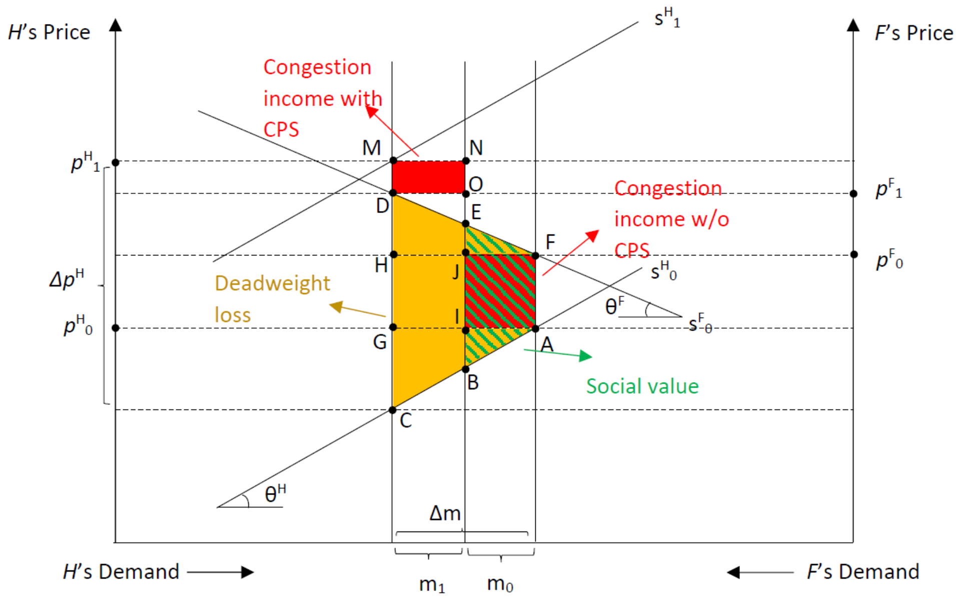


Figure A.3: Impact of CPS on imports and deadweight losses, Case (b)

Figure A.3 presents Case (b). Similar to Cases (a), the deadweight loss is the trapezium ACDF and $L = 1/2 \cdot (\theta^H + \theta^F) \cdot \Delta m^2 + \Delta m \cdot (p_0^F - p_0^H)$. The social value is the trapezium ABEF and $S = 1/2 \cdot (\theta^H + \theta^F) \cdot m_0^2 + m_0 \cdot (p_0^H - p_0^F)$.

The change in congestion income is also $\Delta R = (p_1^F - p_1^H) \cdot m_1 - (p_0^F - p_0^H) \cdot m_0$, where in this case, $m_1 = -m_0 = K$.

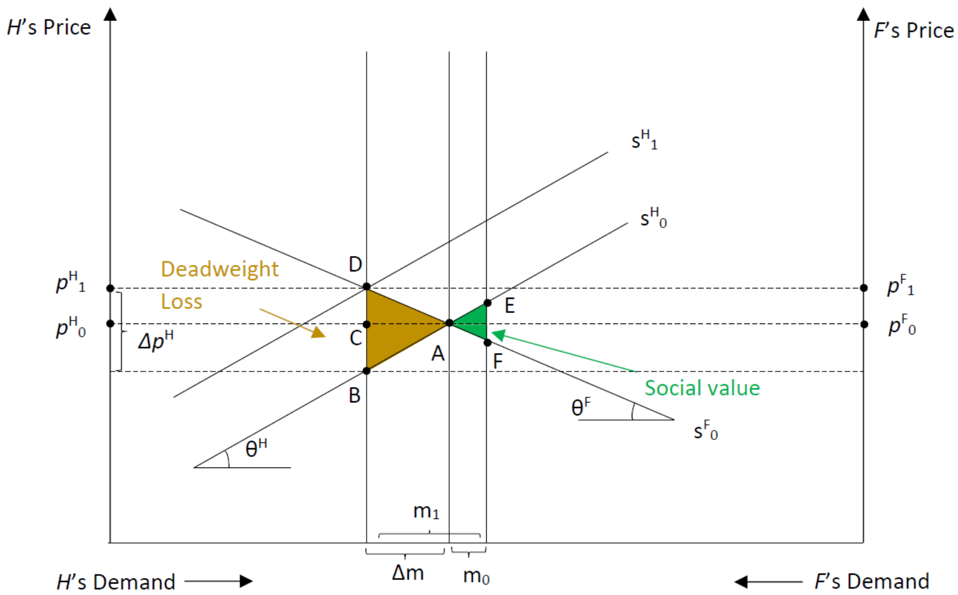


Figure A.4: Impact of CPS on imports and deadweight losses, Case (c)

Figure A.4 presents Case (c), without the CPS, H's net supply curve meets F's net supply curve at point A, with prices equalised ($p_0^H = p_0^F$), no congestion income, and imports at m_0.

The social value is the triangle AEF, or $S = 1/2 \cdot (\theta^H + \theta^F) \cdot m_0^2$ and the deadweight loss is the triangle ABD, or $L = 1/2 \cdot (\theta^H + \theta^F) \cdot \Delta m^2$. As the interconnector flow is unconstrained with and without the CPS, there is no congestion income before or after and hence no change in congestion revenue. In this case, equations (4)-(6) still apply, given $p_j^H = p_j^F$.

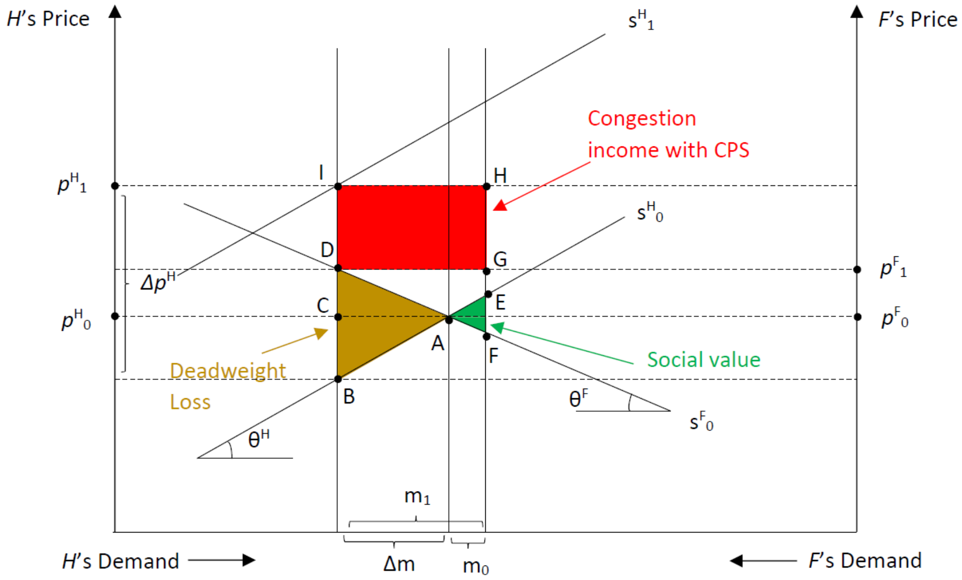


Figure A.5: Impact of CPS on imports and deadweigh losses, Case (d)

Figure A.5 presents Case (d), where exactly the same argument as Case (c) can be made. The triangle ABD measures deadweight losses L and the triangle AEF measures social value S. There is an increase in congestion income $\Delta R = (p_1^H - p_1^F) \cdot m_1$, as shown in Figure A.5 as the rectangle DGHI. Again, equations (4)-(6) still apply in this case given $p_0^H = p_0^F$.

In Case (e), there is no change in trade or output and hence no distortion, but as H's prices increase, so does the price difference $p_1^H - p_1^F$, with consequential changes in the congestion income $\Delta R = m_0 \cdot (p_1^H - p_0^H)$. As a result, there will be a transfer of revenue from H's consumers to the foreign owners of the interconnectors, who, such as the French system operator, shares 50% of the interconnector revenue. Similar to Cases (a) and (b), the social from trading is also $S = 1/2 \cdot (\theta^H + \theta^F) \cdot m_0^2 + m_0 \cdot (p_0^H - p_0^F)$. Finally, given $\Delta m = 0$ and $p_0^F = p_1^F$, equations (4)-(6) still apply.

A.4 Estimating counterfactual flows

As before, superscripts H and F represent the Home and Foreign countries, and subscripts 1 and 0 are with and without the CPS. Variables with "$\sim$" above are scenarios with no interconnector trading, and with "$-$" represents the average over the whole period. Subscripts representing hours are removed to simplify. We implement the following steps to estimate the counterfactual flows:[33]

[33] The most ideal way is to include both IFA and BritNed, but it complicates the matters with negligible gain in terms of making the post-econometric results more robust. Therefore, we analyse IFA and BritNed separately.

1. For each hour, given the actual flows[34] ($m_1 > 0$ for importing and < 0 for exporting) and prices (p_1^H and p_1^F), and the marginal effects of wind on prices (θ_1^H, θ_0^H and θ^F, different before and after April 2015 for H),[35] we can calculate the prices when there is *no trade* ($\tilde{p}_1^H$ and $\tilde{p}_1^F$) as

$$\tilde{p}_1^H = \begin{cases} p_1^H + m_1 \cdot \theta_0^H, & \text{before April 2015} \\ p_1^H + m_1 \cdot \theta_1^H, & \text{after April 2015} \end{cases}$$
$$\tilde{p}_1^F = p_1^F - m_1 \theta^F.$$

2. Assuming that without trading, €1/tCO$_2$ of the British CPS would raise h's price by Δp^H,[36] then the prices *without the CPS* (τ) *and trading*, denoted as $\tilde{p}_0^H$ and $\tilde{p}_0^F$, are

$$\tilde{p}_0^H = \tilde{p}_1^H - \Delta p^H \cdot \tau,$$
$$\tilde{p}_0^F = \tilde{p}_1^F.$$

3. Calculate the interconnector flow where the CPS is not applied (m_0) under the interconnector capacity constraint ($-K < m_0 < K$), taking the Mid Channel loss factor of the interconnector (l) into consideration.[37] Precisely,[38]

$$m_0 = \begin{cases} K, & \tilde{p}_0^H \cdot (1-l) > \tilde{p}_0^F \cdot (1+l) \quad \text{and} \quad K \leq \frac{\tilde{p}_0^H - \frac{1+l}{1-l} \cdot \tilde{p}_0^F}{\frac{1+l}{1-l} \cdot \theta^F + \theta_0^H}, \\ \frac{\tilde{p}_0^H - \frac{1+l}{1-l} \cdot \tilde{p}_0^F}{\frac{1+l}{1-l} \cdot \theta^F + \theta_0^H}, & \tilde{p}_0^H \cdot (1-l) > \tilde{p}_0^F \cdot (1+l) \quad \text{and} \quad K > \frac{\tilde{p}_0^H - \frac{1+l}{1-l} \cdot \tilde{p}_0^F}{\frac{1+l}{1-l} \cdot \theta^F + \theta_0^H}, \\ \frac{\tilde{p}_0^F - \frac{1+l}{1-l} \cdot \tilde{p}_0^H}{\frac{1+l}{1-l} \cdot \theta_0^H + \theta^F}, & \tilde{p}_0^H \cdot (1-l) < \tilde{p}_0^F \cdot (1+l) \quad \text{and} \quad -K < \frac{\tilde{p}_0^F - \frac{1+l}{1-l} \cdot \tilde{p}_0^H}{\frac{1+l}{1-l} \cdot \theta_0^H + \theta^F}, \\ -K, & \tilde{p}_0^H \cdot (1-l) < \tilde{p}_0^F \cdot (1+l) \quad \text{and} \quad -K \geq \frac{\tilde{p}_0^F - \frac{1+l}{1-l} \cdot \tilde{p}_0^H}{\frac{1+l}{1-l} \cdot \theta_0^H + \theta^F}, \\ 0, & \text{otherwise.} \end{cases}$$

---

[34] The day-ahead scheduled IFA flow is collected from RTE.

[35] From Table 2, for off-peak periods, $\hat{\theta}_1^H = 0.289$, $\hat{\theta}_0^H = 1.162$ and $\hat{\theta}^F = 1.898$; for peak periods, $\hat{\theta}_1^H = 1.047$, $\hat{\theta}_0^H = 0.826$ and $\hat{\theta}^F = 1.485$.

[36] Here we assume that the CPS has no direct impact on the French price other than through trading via IFA, which survives statistical tests as discussed in footnote 28.

[37] For IFA, the loss factor is $l = 1.17\%$.

[38] Suppose there is no capacity limit and $\tilde{p}_0^H > \tilde{p}_0^F$, then equalising the prices would require

$$(\tilde{p}_0^H - m_0 \cdot \theta_0^H) \cdot (1-l) = (\tilde{p}_0^F + m_0 \cdot \theta_0^F) \cdot (1+l),$$

or

$$m_0 = \frac{\tilde{p}_0^H - \frac{1+l}{1-l} \cdot \tilde{p}_0^F}{\frac{1+l}{1-l} \cdot \theta^F + \theta_0^H}.$$

The derivation is similarly for $\tilde{p}_0^H < \tilde{p}_0^F$.

4. Derive the counterfactual prices under the counterfactual flows:

$$p_0^H = \tilde{p}_0^H - m_0 \cdot \theta_0^H.$$
$$p_0^F = \tilde{p}_0^F + m_0 \cdot \theta^F.$$

5. Given the actual and counterfactual prices for H and F, we can calculate the average actual and counterfactual prices during the period of study (i.e. $\bar{p}_1^H$, $\bar{p}_0^H$ for H, and $\bar{p}_1^H$, $\bar{p}_0^H$ for F). Then, given the average CPS during the period ($\bar{\tau}$), the effect of the CPS on H's price, *counting in the effect of interconnector trading*, is $(\bar{p}_1^H - \bar{p}_0^H)/\bar{\tau}$.
6. From Steps 1-5, the only unknown parameters is Δp^H in Step 2. Table 2 gives estimates of the marginal effects of the CPS on H's (GB's) prices $(\widehat{\partial p^H/\partial\tau})$. We iteratively adjust the value of Δp^H in Step 2 and repeat Steps 2-5, until $(\bar{p}_1^H - \bar{p}_0^H)/\bar{\tau}$ in Step 5 is equal to $\widehat{\partial p^H/\partial\tau}$ from Table 2 Regression (iii).
7. Once $(\bar{p}_1^H - \bar{p}_0^H)/\bar{\tau}$ and $\widehat{\partial p^H/\partial\tau}$ equate, the associated flows and prices are the counterfactual prices and flows.

Because the undiluted (by trade) effect of the CPS on the GB price (Δp^H in Step 2) is positively correlated with the diluted effect ($(\bar{p}_1^H - \bar{p}_0^H)/\bar{\tau}$ in Step 6, there is a unique Δp^H that equalises $\widehat{\partial p^H/\partial\tau}$ and $(\bar{p}_1^h - \bar{p}_0^H)/\bar{\tau}$ in Step 6.

In these calculations, m_1, p_1^H, p_1^F, τ, K, and l are observed, while θ_1^H, θ_0^H, θ^F and $\partial p^H/\partial\tau$ are estimated separately for peak and off-peak periods.

Using point estimates of θ_1^H, θ_0^H, θ^F and $\partial p^H/\partial\tau$ only gives point estimates of the counterfactuals. To circumvent this problem, we assume that the actual values of θ_1^H, θ_0^H, θ^F and $\partial p^H/\partial\tau$ follow a jointly normal distribution, with mean and variance-covariances equal to the estimated values from Regression (iii). We then apply a Monte Carlo technique to take 500 random draws from the jointly normal distribution, and for each draw, we follow Steps 1-7 to obtain the counterfactual electricity prices and flows and hence the annual average electricity prices, net imports and congestion income. The resulting means and the standard deviations of the counterfactuals are reported in Table 3.

A.5 Estimating market distortion

In this subsection, we use the same 500 combinations of counterfactuals to estimate the social value of trading and deadweight losses from asymmetric carbon taxes discussed in Section 3.2. In addition, as the CPS does not apply to the increased GB imports, we estimate the loss in the GB government's carbon-tax revenue from the reduction in GB generation displaced,.

From Section 6.1 and Appendix A.4, given $\hat{\theta}_0^H$ and $\hat{\theta}^F$, and the estimated m_0, Δm, p_0^F and p_0^H, the social value is $1/2 \cdot (\hat{\theta}_0^H + \hat{\theta}^F) \cdot m_0^2 + m_0 \cdot (p_0^H - p_0^F)$, and the deadweight loss is $1/2 \cdot (\hat{\theta}_1^H + \hat{\theta}_1^F) \cdot \Delta m^2 + \Delta m \cdot (p_0^F - p_0^H)$. Finally, the carbon-tax revenue loss is defined as the product between the change in trading volumes (Δm) and GB's marginal emission factors (MEFs), μ_1^H, estimated yearly by Chyong et al. (2020).

A.6 Estimating the Marginal Emission Factors for France

France is apparently well-connected to Germany, Belgium and NL and these have higher carbon intensities, as Figure A.6 shows.

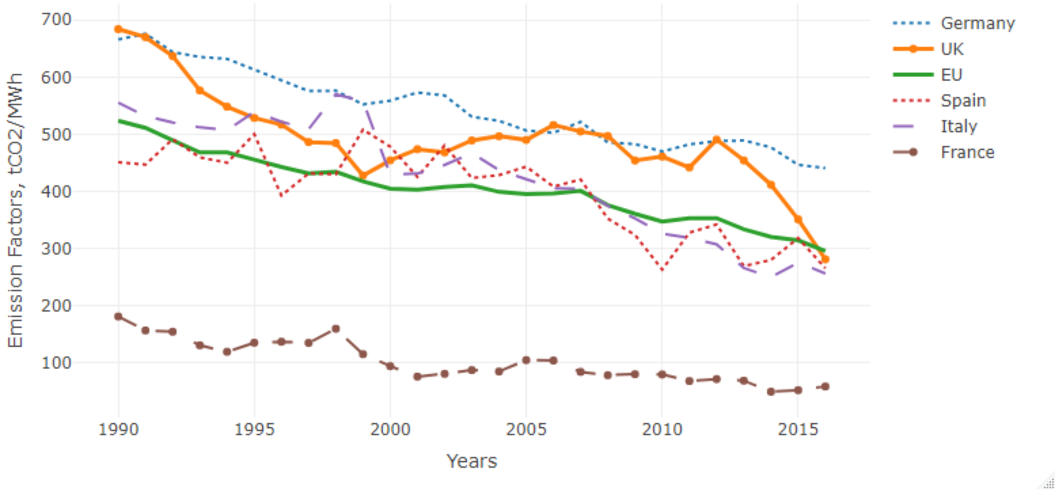


Figure A.6: Carbon intensity of electricity, 1990-2016

Table A.2 shows the shares of fossil fuels in 2017 in France and its interconnected neighbours. In all these countries gas is the dominant fossil fuel, but coal was more expensive (including the EUA price) than gas in 2017-2018. While gas is more flexible than coal, coal might have been price-setting at least part of the time.

To investigate this further Table A.3 estimates the share of fossil fuel responses to increased fossil demand. For the cases of Belgium, all responses at the margin come from changes in CCGT output. In the case of Germany, Spain, and France, where there are several fossil fuels simultaneously generating, response is measured by looking at the change of each fuel from the previous hour compared to the change in all fossil output over that hour, adjusted to add to 100%. For Germany and Spain, most of the response is from lignite and coal, with a higher MEF, giving the average as 0.68 tCO_2/MWh and 0.48 tCO_2/MWh, respectively. Our estimated German MEF is not very different from the modelled for Germany for 2020 of 0.63 tCO_2/MWh from Böing and Regett (2019). (Northern) Italy has gas and "other" as fossil fuels. While we have no further information on what "other" represents, we assume it is some combinations of lignite, coal, gas and biomass, whose emission factor is half of coal and lignite. The MEF for Italy is taken at 0.38 tCO_2/MWh. Switzerland has no fossil fuels, but it is densely connected to Germany and (Northern) Italy, hence we assume its MEF is the average of those in Germany and Italy, or 0.53 tCO_2/MWh. Finally, as Belgium is 100% gas, its MEF is taken at 0.34 tCO_2/MWh.

The next step is to determine the MEF when IFA is uncongested, and that will depend on whether is trading freely with Continental neighbours. If France's borders are all uncongested in any hour then it is assumed that the MEF is the average of the MEFs of the uncongested neighbours plus France, weighted by their shares in their total fossil generation, otherwise it is

Table A.2: Share of different fuels in generation, 2017

Country	Lignite	Coal	Oil	Gas	Other
Germany	22%	11%	0%	5%	
Spain	2%	15%	1%	23%	
Italy				27%	42%
Belgium	0%	0	0%	27%	
France		2%	0%	8%	

Table A.3: Contribution of fossil fuels to flexibility, 2017

	Fossil Fuels					
Country	Lignite	Coal	Oil	Gas	Other	MEF (fossil only)
Germany	29%	45%	1%	25%		0.68
Spain	5%	31%	1%	63%		0.48
Italy				51%	49%	0.53
Switzerland						0.53
Belgium				100%		0.34
France		23%	10%	67%		0.46

the weighted average of the remaining uncongested links with France. If France is isolated then it is just the French MEF. The results are shown in table A.4, assuming the same responsive fossil shares in each year.

Table A.4: percent time link constrained when IFA unconstrained and MEF for France

	Interconnectors					
	FR-BE	FR-DE	FR-ES	FR-IT	FR-CH	MEF
15-16	67%	83%	53%	56%	64%	0.463
16-17	59%	73%	69%	66%	64%	0.456
17-18	60%	74%	69%	66%	65%	0.461

A.7 Estimating the impact of the CPS on BritNed

Due to data availability, our analysis on BritNed runs from January 2015 to September 2018. Electricity load, wind and nuclear generation for The Netherlands and the net transfer capacity of BritNed are collected from the ENTSO-E Transparency Platform. Unfortunately, there is no reliable data source providing BritNed's day-ahead scheduled flow. We simulate the hourly BritNed day-ahead flow using the following algorithm:

- if both the unadjusted price differential (UPD) and adjusted price differential (APD)[39] are greater (or smaller) than zero, the interconnector capacity (K) will be fully used for importing (or exporting);
- if the APD is zero and the UPD is positive, then the day-ahead commercial exchange would be randomly (uniformly) allocated within the interval between zero and K;

[39] Adjusted by the BritNed loss factor of 3%, see https://www.britned.com/about-us/operations/.

Table A.5: M-GARCH Results, BritNed

Mean Equations

	Unit	Great Britain Off	Great Britain Peak	The Netherlands Off	The Netherlands Peak
(Constant)		-7.226^{**}	-5.675^{*}	-3.926	-16.54^{***}
		(2.302)	(2.332)	(2.631)	(3.181)
GB load	GW	0.501^{***}	0.594^{***}	0.153^{**}	0.464^{***}
		(0.050)	(0.033)	(0.055)	(0.044)
Dutch load	GW	-0.111^{*}	0.114^{*}	0.248^{***}	-0.152^{*}
		(0.052)	(0.055)	(0.052)	(0.074)
GB Nuclear	GW	-0.681^{***}	-0.671^{***}	-0.027	0.239
		(0.144)	(0.152)	(0.134)	(0.194)
Dutch Nuclear	GW	-0.718	-2.907^{***}	-1.703^{***}	-5.061^{***}
		(0.533)	(0.549)	(0.497)	(0.691)
GB wind	GW	-0.432^{***}	-0.916^{***}	-0.051	-0.065
		(0.060)	(0.050)	(0.063)	(0.072)
Dutch wind	GW	-0.060	0.138	-2.377^{***}	-1.814^{***}
		(0.151)	(0.128)	(0.157)	(0.182)
BritNed capacity	GW	-0.862	-3.709^{***}	0.087	0.991
		(0.804)	(0.654)	(0.893)	(0.810)
Coal price	€/MWh$_e$	0.326^{***}	0.349^{***}	0.466^{***}	0.449^{***}
		(0.024)	(0.028)	(0.025)	(0.034)
Gas price	€/MWh$_e$	0.804^{***}	0.823^{***}	0.499^{***}	0.866^{***}
		(0.019)	(0.023)	(0.023)	(0.033)
EUA	€/tCO$_2$	0.469^{***}	0.459^{***}	0.768^{***}	0.551^{***}
		(0.032)	(0.036)	(0.036)	(0.058)
CPS	€/tCO$_2$	0.412^{***}	0.558^{***}	-0.198^{***}	0.021
		(0.035)	(0.034)	(0.042)	(0.046)

Conditional Variance Equations

	Great Britain Off	Great Britain Peak	The Netherlands Off	The Netherlands Peak
(Constant)	2.836^{***}	0.731^{***}	1.816^{***}	1.087^{***}
	(0.407)	(0.139)	(0.394)	(0.245)
ARCH	0.661^{***}	0.348^{***}	0.395^{***}	0.251^{***}
	(0.088)	(0.049)	(0.063)	(0.030)
GARCH	0.278^{***}	0.699^{***}	0.495^{***}	0.742^{***}
	(0.055)	(0.028)	(0.071)	(0.025)

Standard errors in parentheses. $^{*}p < 0.05$, $^{**}p < 0.01$, $^{***}p < 0.001$.

- if the APD is zero and the UPD is negative, day-ahead flows would be randomly (uniformly) allocated as a negative number between $-K$ and zero;
- if the APD and UPD have different signs, we assume the direction of flows follows that in the previous hour, and the volume of the flow is randomly taken from the uniform distribution between zero and K.

Due to consistency and data quality concerns, the impact of GB's import/wind and the CPS on the GB prices are taken from Regression (iii) in Table 2, and the impact of the Dutch wind on its prices are taken from our new estimates for BritNed. Because of this, we will not include interaction terms between variables and follow Regression (ii)'s specification (but excluding the dummy variable for the French nuclear outages)[40] to study the impact of the Dutch wind on its wholesale prices. The estimation results are reported in Table A.5 as Regression (iv), showing that during off-peak (peak) periods, a 1 GW increase in the Dutch wind generation (or Dutch exports) is associated with a €2.4 (1.8)/MWh reduction in its off-peak(peak) wholesale prices. The magnitudes are higher than those in GB and France mainly because the electricity demand in The Netherlands is much lower.

Table A.6: Statistical Measurements for BrtiNed: prices, flows, and congestion revenue

Electricity	**GB Prices (€/MWh)**			**Dutch Prices (€/MWh)**		
years	w. CPS	w/o CPS	Δ	w. CPS	w/o CPS	Δ
15-16	€53.24	€40.52	€12.72	€36.25	€35.24	€1.01
		(0.93)	(0.93)		(0.14)	(0.14)
16-17	€51.76	€40.70	€11.07	€35.98	€35.01	€0.97
		(0.81)	(0.81)		(0.14)	(0.14)
17-18	€52.70	€42.24	€10.46	€39.87	€38.80	€1.07
		(0.77)	(0.77)		(0.13)	(0.13)
Ave.(15-18)	€52.57	€41.15	€11.42	€37.37	€36.35	€1.02
		(0.84)	(0.84)		(0.13)	(0.13)
	GB Net Import (TWh)			**Congestion Income (m €)**		
	w. CPS	w/o CPS	Δ	w. CPS	w/o CPS	Δ
15-16	8.21 TWh	3.49 TWh	4.72 TWh	€134	€60	€74
		(0.58)	(0.58)		(3.31)	(3.31)
16-17	7.28 TWh	2.71 TWh	4.57 TWh	€121	€68	€53
		(0.56)	(0.56)		(2.34)	(2.34)
17-18	7.14 TWh	2.11 TWh	5.03 TWh	€97	€51	€46
		(0.50)	(0.50)		(1.94)	(1.94)
Ave.(15-18)	7.54 TWh	2.77 TWh	4.77 TWh	€117	€59	€58
		(0.54)	(0.54)		(2.51)	(2.51)

Standard errors in parentheses.

Note that Table A.5 can be used as a robustness check for our IFA study in Table 2. Both studies show some similar magnitudes for the slope coefficients of GB wind, coal and gas prices, as well as EU and British carbon price impacts on GB prices. Perhaps surprisingly, we

[40] The dummy variable is not statistically significant even if we include it in the regressions.

find the CPS has a negative impact on off-peak Dutch prices. The could be that the data only allow us to have few observations with a CPS of £9.55/tCO_2. Estimates of the effects of the CPS on the wholesale prices are vulnerable to unexpected shocks — for example, the winter of 2016 was one of the warmest in Dutch history, resulting in less domestic heating load and lower electricity prices. Fortunately, this would not affect our post-econometric analysis as we assume that without interconnector trading, the impacts of the CPS on the foreign wholesale prices are zero.

Using the result from Tables 2 and A.5, and applying the same steps as Section A.4, Table A.6 reports the counterfactuals of the GB and Dutch wholesale prices, as well as the net import and congestion income of BritNed. Our results for BritNed are cosistent with our IFA analysis in Section 6.1-6.3. During electricity years 2015-2018, the CPS on average raised Dutch wholesale prices by €1.02/MWh, or about 2.8%. About 63% (4.77 TWh) of GB's net import from The Netherlands is due to the CPS, and the associated congestion income almost doubled from €59 m/yr to €117 m/yr.

Table A.7: BritNed: surplus, distortion and losses

Electricity years	**Social Value (m €)**	**Deadweight Loss (m €)**	**GB CPS Rev. Loss (m €)**
15-16	€78	€40.6	€47.2
	(3.69)	(5.17)	(5.76)
16-17	€85	€37.1	€35.4
	(2.70)	(4.41)	(4.44)
17-18	€68	€39.6	€34.8
	(2.15)	(4.60)	(3.51)
Ave. 15-18	€77	€39.1	€39.2
	(2.83)	(4.73)	(4.55)

Standard errors in parentheses.

The effects of the CPS on the Dutch price, GB's net import and congestion revenue from BritNed are more than half of those from our IFA estimates. Although BritNed is half the size of IFA, the slope of the Dutch supply curve (measured by the impact of wind on the Dutch price) is steeper than GB and France because of its smaller electricity load. Table A.7 further shows that during electricity years 2015-2018, the social value of BritNed is €77 m/yr and the deadweight loss is €39.1 m/yr, about half of the social value of IFA's social value and about the same size of the IFA loss. The UK government has lost about €39.2 million worth of tax revenue, or about 4% of its total CPF receipts in 2017.

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